2015 Congestion Assessment and Resource Integration Study

Comprehensive System Planning Process

CARIS – Phase 1

November XX, 2015

NYISO System Resources and Planning staff can be reached at 518-356-6000 to address any questions regarding this CARIS report or the NYISO's economic planning processes.

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Executive Summary

1. Overview

With the publication of this *2015 Congestion Assessment and Resource Integration Study (CARIS) Phase 1 Report,* the New York Independent System Operator, Inc. (NYISO) has completed the first phase (CARIS Phase 1) of its two-phase economic planning process.[1] This CARIS Phase 1 report provides information to market participants, policy makers, and other interested parties for their consideration in evaluating projects designed to address congestion costs identified in the study. The report presents an assessment of historic (2010-2014) and projected (2015-2024) congestion on the New York State bulk power transmission system and provides an analysis of the potential costs and benefits of relieving that congestion using generic projects as solutions.

The report also discusses key assumptions adopted for this analysis, and changes in the system topology and forecasts of key model inputs from the prior CARIS Phase 1 analysis, some of which resulted in reduced congestion projections for the next 10 years, for example, the construction of the Transmission Owner Transmission Solutions (TOTS) in 2016 and lower load and natural gas price forecasts. The TOTS projects, which enhance the transfer capability across Marcy South, tend to decrease the overall level of congestion across the UPNY-SENY interface. Similarly, lower load and fuel price forecasts for the ten-year study period tend to reduce demand congestion across both UPNY-SENY and Central East, two of the most congested New York Control Area (NYCA) interfaces. An overview of the major assumption changes appears later in this Executive Summary with additional details provided in Section 4.1 of the main report.

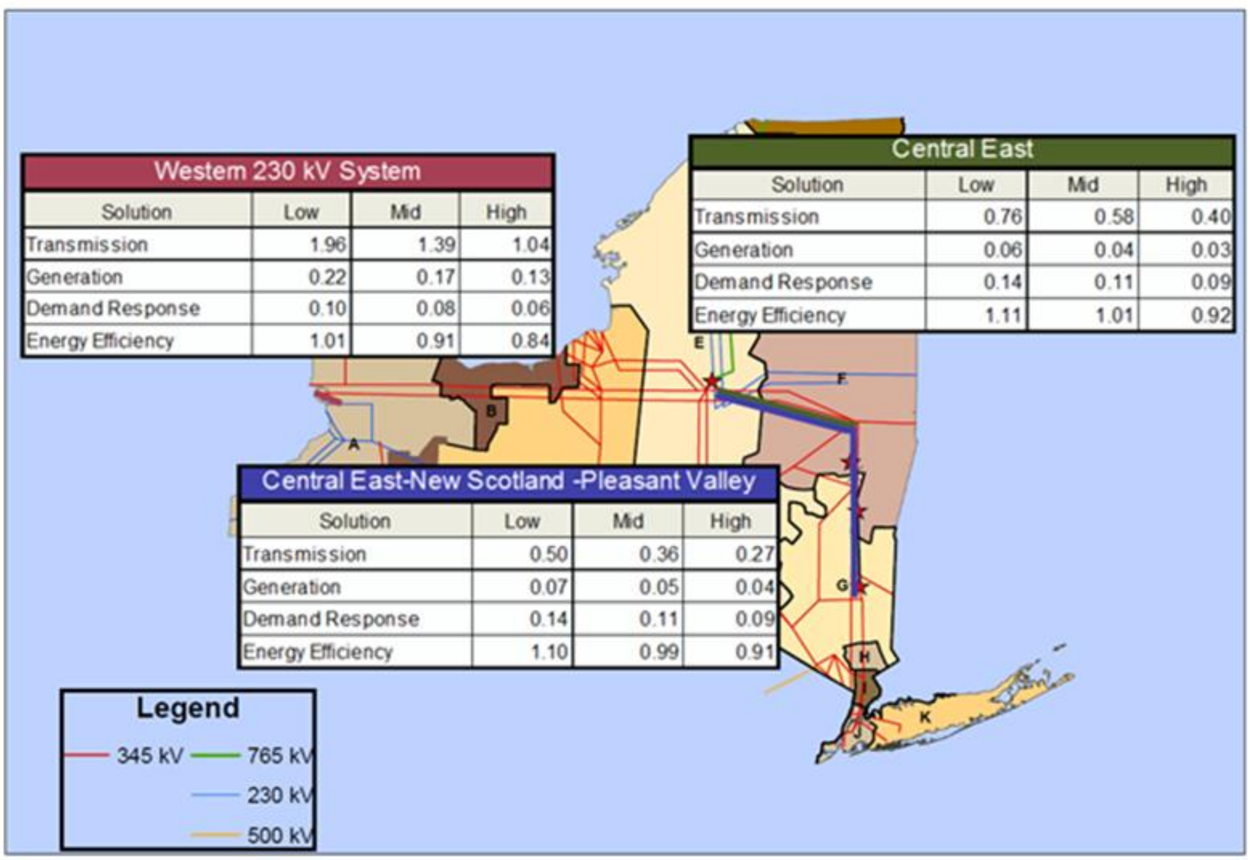
Generic solutions –transmission, generation, demand response (DR) and energy efficiency (EE) – were applied to relieve congestion for the three most congested elements or group of elements in the NYCA without assessing the feasibility of such projects. In accordance with Attachment Y of the NYISO's Open Access Transmission Tariff (OATT), the primary metric to measure benefits to be used in the benefit-cost analysis is the NYCA-wide production cost savings. In order to provide more information, additional benefit metrics such as emissions costs, load and generator payments, Installed Capacity (ICAP) savings, and Transmission Congestion Contract (TCC) payments are also presented. While some versions of these metrics indicated significant additional benefits, it is important to note that they were not included among the benefits used in calculating the benefit to cost (B/C) ratio, which is limited to production cost savings in accordance with Attachment Y to the NYISO's Open Access Transmission Tariff (Tariff) requirements. The costs of the generic solutions were based

[1] Capitalized terms not otherwise defined herein have the meaning set forth in Section 1 and Attachment Y of the NYISO's OATT.

upon estimates of low, mid and high solution costs that were reviewed with Market Participants, including Transmission Owners. The B/C ratios for the generic solutions are shown in Figure 1.

As reflected in the variance in B/C ratios across the three studies and across solutions within the studies, there is a significant range in production cost savings and solution costs. For the two Central New York studies, the transmission, generation and demand response solutions produced a B/C ratio less than one in each of the cost estimate categories, reflecting the fact that their projected costs outweighed their estimated production cost savings over the Study Period. The energy efficiency solution for the Central East constraint produced a B/C ratio greater than one in the Low and Mid cost estimates, and, similarly, the energy efficiency solution for the Central East-New Scotland-Pleasant Valley constraint produced a B/C ratio greater than 1.0 for the Low cost estimate and is approximately 1.0 (0.99) for the Mid cost estimate. For the Western NY study, the Transmission solution had B/C ratios in excess of 1.0 in each of the cost categories. Similar to the Central New York studies, the generation and demand response solutions had B/C ratios well below 1.0, and the energy efficiency solution was greater than 1.0 in the Low cost estimate category and approaching 1.0 for the Mid cost estimate.

Three Congestion Studies: Ratios of Production Cost Savings to Solution Costs (B/C Ratios)



Western 230 kV System

Solution	Low	Mid	High
Transmission	1.96	1.39	1.04
Generation	0.22	0.17	0.13
Demand Response	0.10	0.08	0.06
Energy Efficiency	1.01	0.91	0.84

Central East

Solution	Low	Mid	High
Transmission	0.76	0.58	0.40
Generation	0.06	0.04	0.03
Demand Response	0.14	0.11	0.09
Energy Efficiency	1.11	1.01	0.92

Central East-New Scotland -Pleasant Valley

Solution	Low	Mid	High
Transmission	0.50	0.36	0.27
Generation	0.07	0.05	0.04
Demand Response	0.14	0.11	0.09
Energy Efficiency	1.10	0.99	0.91

Figure 1: Generic Solutions Benefit/Cost Ratios (Low, Mid and High Cost Estimates)

This 2015 CARIS Phase 1 report was developed in compliance with the NYISO's OATT which prescribes production cost savings as the primary metric to be used in calculating the benefit-cost ratios of proposed generic upgrades and projects. The B/C ratios, therefore, do not capture reduced Demand$ Congestion which are $2.22B – $2.5B in 2015$ for the Central NY transmission solutions; and nearly $340M (2015$) for the Western NY transmission solution[2]. Likewise, capacity market impacts are not reflected in the B/C ratios. For example, the Variant 1 estimate[3] of the capacity market impact, if the capacity benefits were to be realized, for the Central East-New Scotland-Pleasant Valley transmission solution was a savings of $377M (2015$); for the Central East transmission solution, an increase of $82M (2015$); and the Western NY 230 kV system transmission solution, no change.

The OATT identifies other metrics, such as capacity market and environmental impacts, as "Additional Metrics" and requires that these be evaluated and presented for informational purposes only. There may be other benefits, not identified in the OATT, such as impacts to system reliability, grid operations, economic development, property taxes and employment, which were not considered in the 2015 CARIS report. As a result, the benefit-cost ratios presented in the 2015 CARIS Report reflect some, but not necessarily all of the benefits associated with transmission upgrades or other potential solutions to address system congestion. The benefits of proposed upgrades may be evaluated in other contexts by examining additional metrics beyond production cost savings and may yield materially different benefit-cost ratios for a specific project based on the particular metrics evaluated.

2. Summary of Study Process and Results

A. The Three Congestion Studies

Consistent with the CARIS procedures, the NYISO ranked and grouped transmission elements with the largest production cost savings when congestion on that

[2] One of the key metrics in the CARIS analysis is termed Demand Dollar congestion (Demand$ Congestion). Demand$ Congestion represents the congestion component of load payments which ultimately represents the cost of congestion to consumers. For a Load Zone, the Demand$ Congestion of a constraint is the product of the constraint shadow price, the Load Zone shift factor (SF) on that constraint, and the zonal load. For NYCA, the Demand$ Congestion is the sum of all of the zonal Demand$ Congestion.

[3] See footnote 5 for a description of the capacity market metrics which were developed in compliance with Section 31.3.1.3.5.6 of the Tariff.

constraint was relieved. The groupings selected for the three 2015 CARIS studies are shown in Figure 2 along with the present value of projected congestion. Specifically, the studies are: Central East - New Scotland - Pleasant Valley (Study 1), Central East (Study 2), and the Western 230 kV System (Study 3) and the annual congestion is shown in Figure 3. While the Central New York studies have been included in prior CARIS analyses, this is the first cycle in which the Western New York system has been studied to assess the relative costs and benefits of relieving system congestion on production costs.

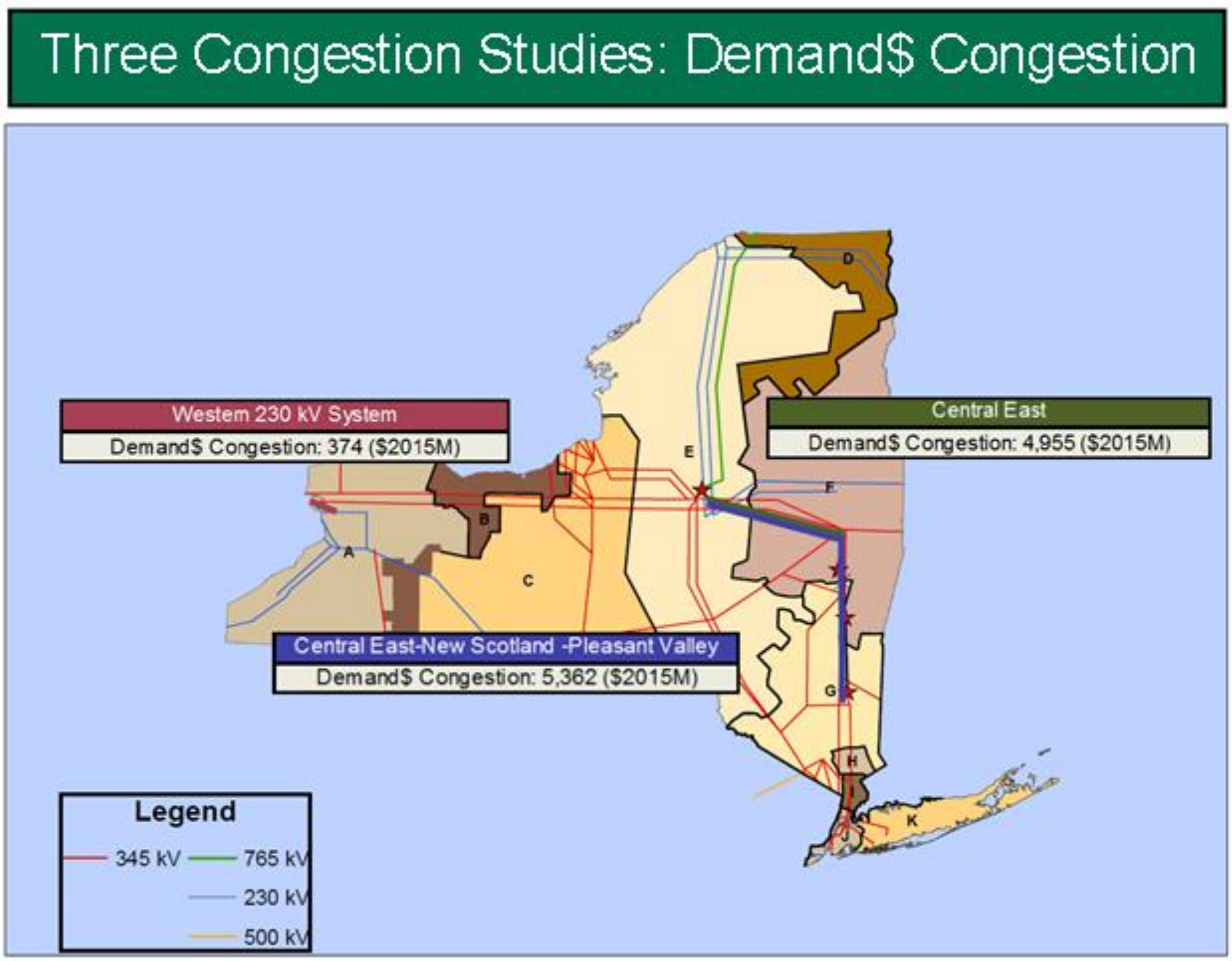


Figure 2: Congestion on the Top Three CARIS Groupings (Present Value in 2015 $M)

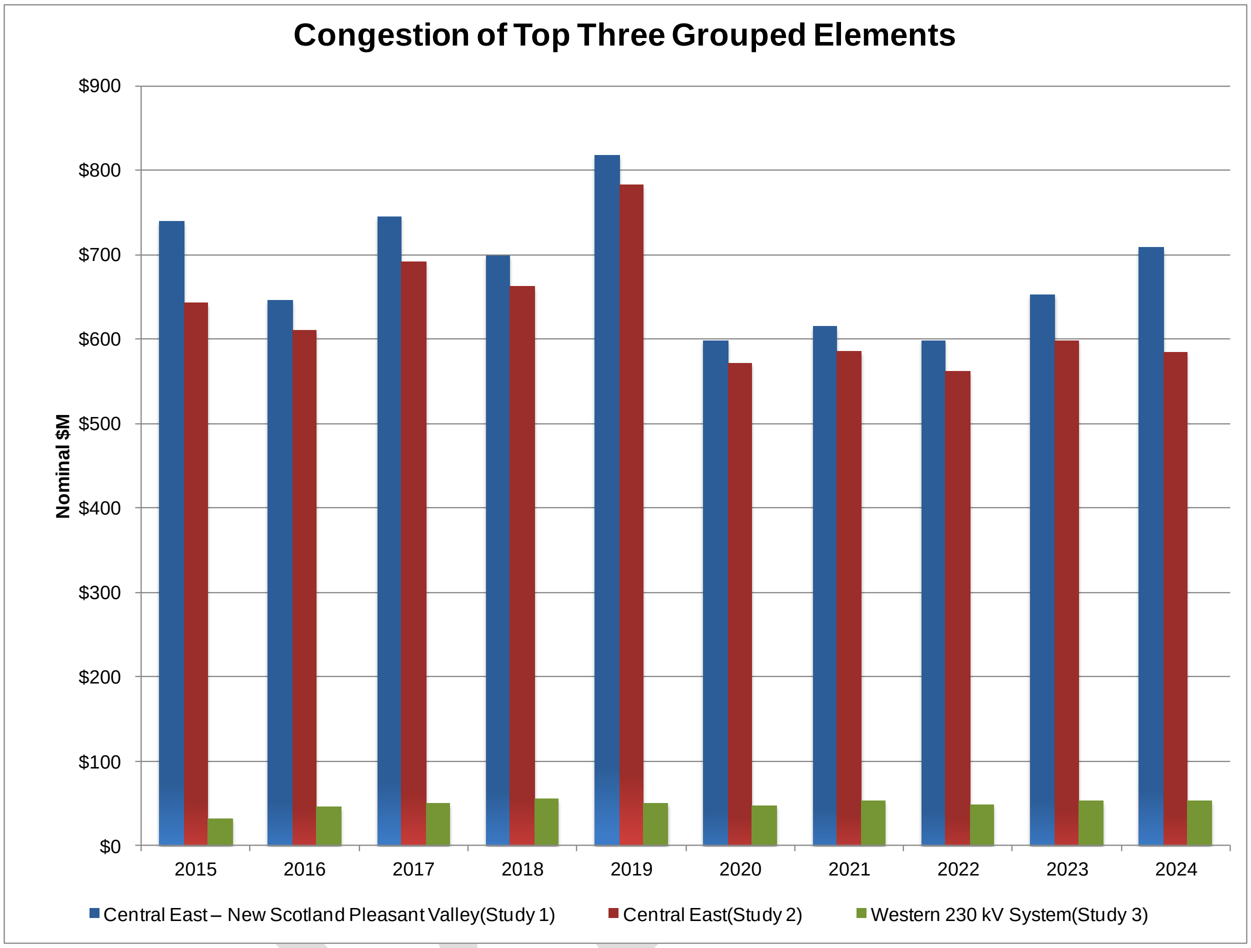


Figure 3: Projected Congestion on the Top Three CARIS Groupings (Nominal $M)

Tariff provisions direct that the CARIS analysis study four solution types for each of the selected studies (*i.e.*, transmission, generation, demand response and energy efficiency) and that the studied solutions be considered on a comparable basis. Toward this end, the NYISO sizes the solutions such that the MWs of generation, demand response and energy efficiency approximate the increase in transfer capability across the relevant interface created by the transmission solution.

Consistent with CARIS 2013, the NYISO initially determined an appropriate transmission solution for each of the three studies based on its engineering judgment and a review of pending proposed transmission projects. For Study 1 and 2, this entailed a new 345 kV transmission line with a line rating of 1,986 MVA connecting the buses immediately upstream and downstream of the congested interface. For the CE-NS-PV study, this resulted in an increased transfer capability of approximately 700 MW across Central East and 1,200 MW across UPNY-SENY; for the CE study , this resulted in an increased transfer capability of approximately 600 MW across Central East and a decrease of 124 MW across UPNY-SENY. For Study 3, a new 230 kV transmission line between Niagara and Gardenville with a rating of 566 MVA was studied with an associated increase in transfer capability across Dysinger East of 630 MW.

The NYISO then sized the generation solutions comparable to the increase in transfer capability provided by the transmission solutions. The sizes for the other solutions (energy efficiency and demand response) were similarly constructed such that the overall MW size was comparable to the increase in transfer capability associated with the transmission solution for the study in question.

The generation solutions for each of the study groups were sited at different locations consistent with the end-points of the transmission solutions. The generation solution for the CE-NS-PV was sited at Pleasant Valley. The NYISO modeled a new 1,320 MW combined cycle plant at this location. The generation solution for CE is a 660 MW plant sited at New Scotland, downstream of the Central East interface. Similarly, a 660 MW plant is sited at Gardenville for the Western 230 kV study.

The energy efficiency solution is modeled by load reductions for the impacted load zones. For the CE-NS-PV and CE studies, the energy efficiency solution was modeled in F, G and J; for the West study, the solution was modeled in A, B and C. The demand response solutions were modeled in the same location and block sizes as the energy efficiency solutions, but only for the 100 peak hours.

Table 1 presents a summary of the solution sizes.

Table 1: Generic Solutions

Generic Solutions			
Studies	Study 1: Central East-New Scotland-Pleasant Valley	Study 2: Central East	Study 3: Niagara-Gardenville
TRANSMISSION			
Transmission Path	Edic to New Scotland to Pleasant Valley	Edic to New Scotland	Niagara to Gardenville
Voltage	345 kV	345 kV	230 kV
Miles	150	85	35
GENERATION			
Unit Siting	Pleasant Valley	New Scotland	Gardenville
# of 330 MW Blocks	4	2	2
DR			
Locations (# of Blocks)	F (1) , G(1) and J(4)	F (1), G (1) and J (1)	A (1), B(1) and C (1)
Total # of 200 MW Blocks	6	3	3
EE			
Locations (# of Blocks)	F (1) , G(1) and J(4)	F (1) ,G (1) and J (1)	A (1), B(1) and C (1)
Total # of 200 MW Blocks	6	3	3

Costs for each type of generic solution were presented through the stakeholder process, but no determination was made as to the feasibility of any generic solution.

Recognizing that the costs, points of interconnection, timing, and characteristics of actual projects may vary significantly, a range of costs (low, mid and high) was developed for each type of resource based on publicly available sources. For the demand response solution, the costs do not reflect energy payments to demand-response providers participating in the NYISO's demand-response programs or any additional payments received through the utility program.

The present value of the estimated carrying costs for each of the generic solutions was compared to the present value of projected production cost savings for a ten-year period (2015-2024), yielding a benefit/cost ratio for each generic solution. The benefit/cost ratios displayed in Figure 1 are based on the present value in 2015 dollars of the NYCA-wide production cost savings accumulated over the ten year period as shown in Figure 4. For purposes of a relative order of magnitude comparison, nominal electric production costs of New York generators over the Study Period range between $3B and $5B annually.

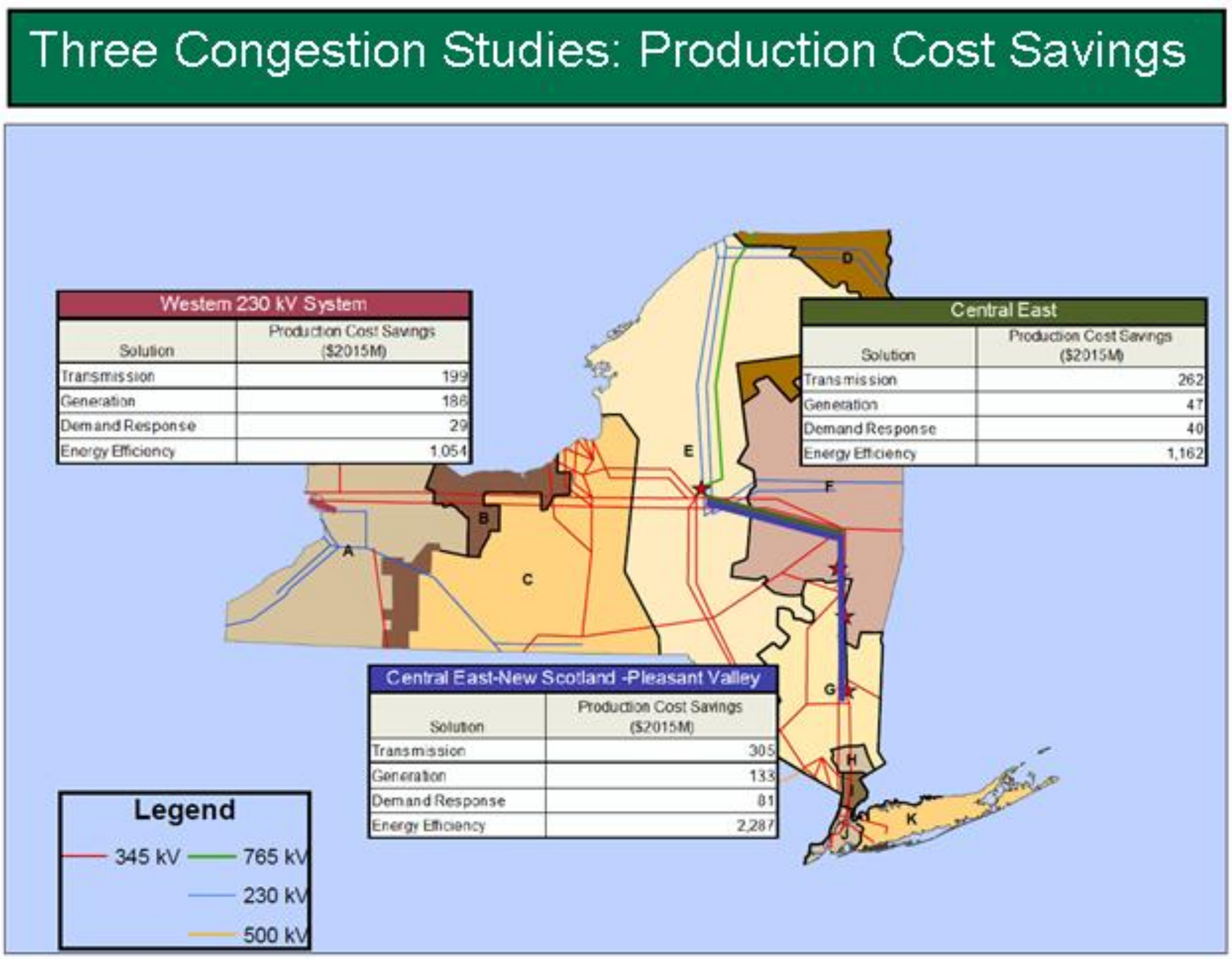


Figure 4: NYCA-wide Production Cost Savings (2015$M)

B. Additional Metrics

In addition to the NYCA-wide production cost savings for each generic solution, the NYISO also has provided, for informational purposes, additional metrics for each of the three studies and each of the generic solutions in terms of changes in:

a. emission quantities and costs,

b. NYCA generator payments,

c. locational based marginal price (LBMP) load payments[4],

d. installed capacity (ICAP) savings[5],

e. loss payments for losses on the transmission system, and

f. congestion rents or transmission congestion contracts (TCCs) payments.

All but the ICAP metric are results of the production cost simulation program and show either increases or decreases depending primarily on which solution is modeled. The ICAP metrics are computed using the latest available information from the installed reserve margin (IRM), locational capacity requirement (LCR), and ICAP Demand Curves.

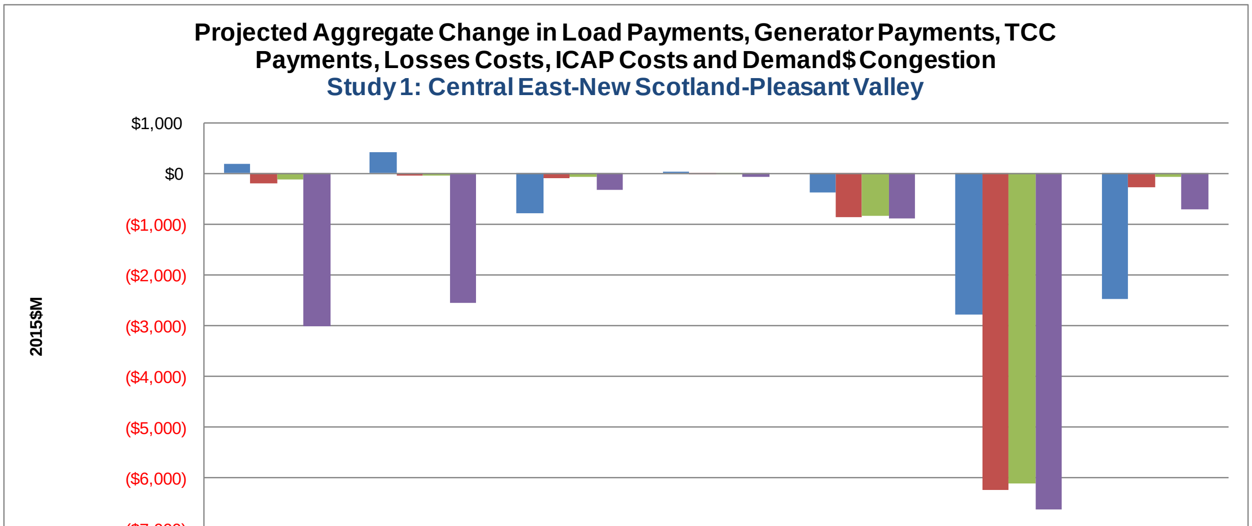
Figures 5, 6 and 7 below present, in graphical form, the changes in the additional metric quantities for each of the three study cases. The total ten-year present value amounts for these metrics are presented in 2015$M. Negative numbers (shown in brackets) represent reductions in those metric quantities. Some metrics are not limited to payments made only by NYCA load or to payments made only to NYCA generators. Load payments include export costs, and generator payments include import costs.

The increase in ICAP costs for the Central East transmission solution is attributable to the impact of the 2nd Edic-to-New Scotland line on the UPNY-SENY interface transfer limits. Although the new transmission line results in an increase in the Central East interface limit of 700 MW, it reduces the UPNY-SENY limit by 124 MW which leads to an $82M increase in Variant 1 and $608M in Variant 2. The ICAP MW Impact for the Western 230 kV study transmission solution was 0 MW under the CARIS

[4] For the purposes of this study, the load payment metric does not reflect that loads may be partially hedged through bilateral contracts and ownership of TCCs.

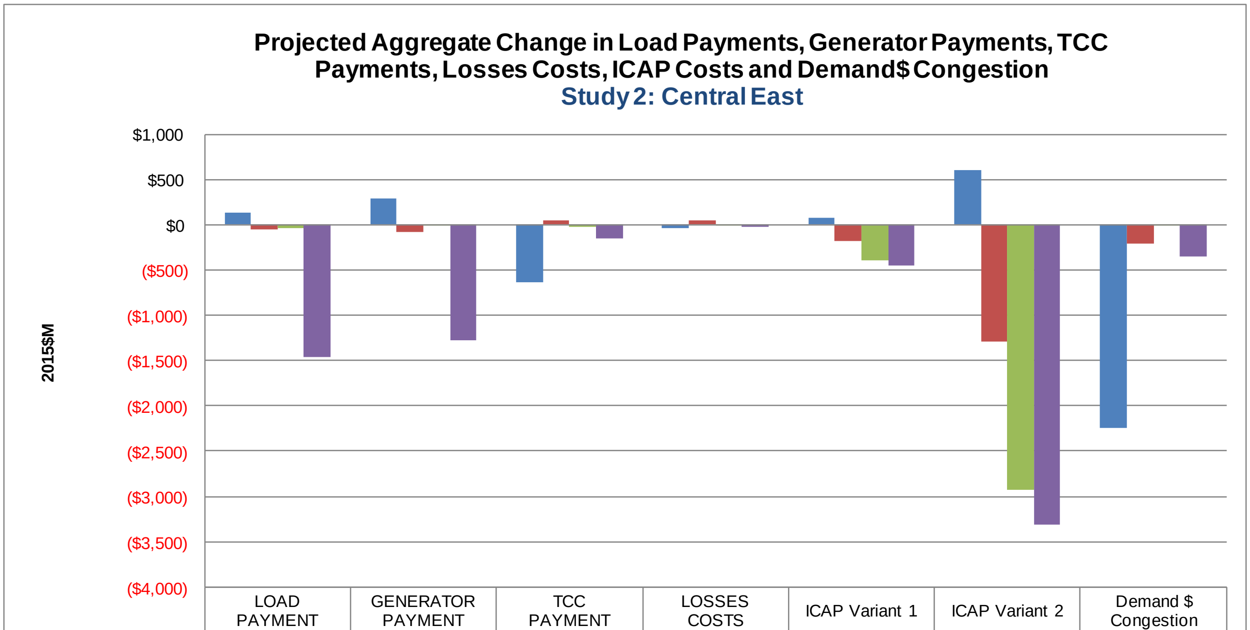
[5] Per the OATT, there are two variants of the capacity market metric. For Variant 1, the ISO measured the cost impact of a solution by multiplying the forecast cost per megawatt-year of Installed Capacity (without the solution in place) by the megawatt impact for each solution. For Variant 2, the cost impact of a solution is calculated by forecasting the difference in cost per megawatt-year of Installed Capacity with and without the solution in place and multiplying that difference by fifty percent (50%) of the assumed amount of NYCA Installed Capacity available. The 50% value is intended to represent the amount of capacity not procured through bilateral aggreements.

assumptions and methodology due to the absence of constraints across the Dysinger East and Zone A Group interfaces in the Base Case. These interfaces were not materially constraining in the 2024 case due to low load growth and the increased penetration of solar PV installations. These results illustrate the generic nature of the solutions studied. These solutions may not be optimal in solving all system constraints but do resolve significant portions of the projected congestion.



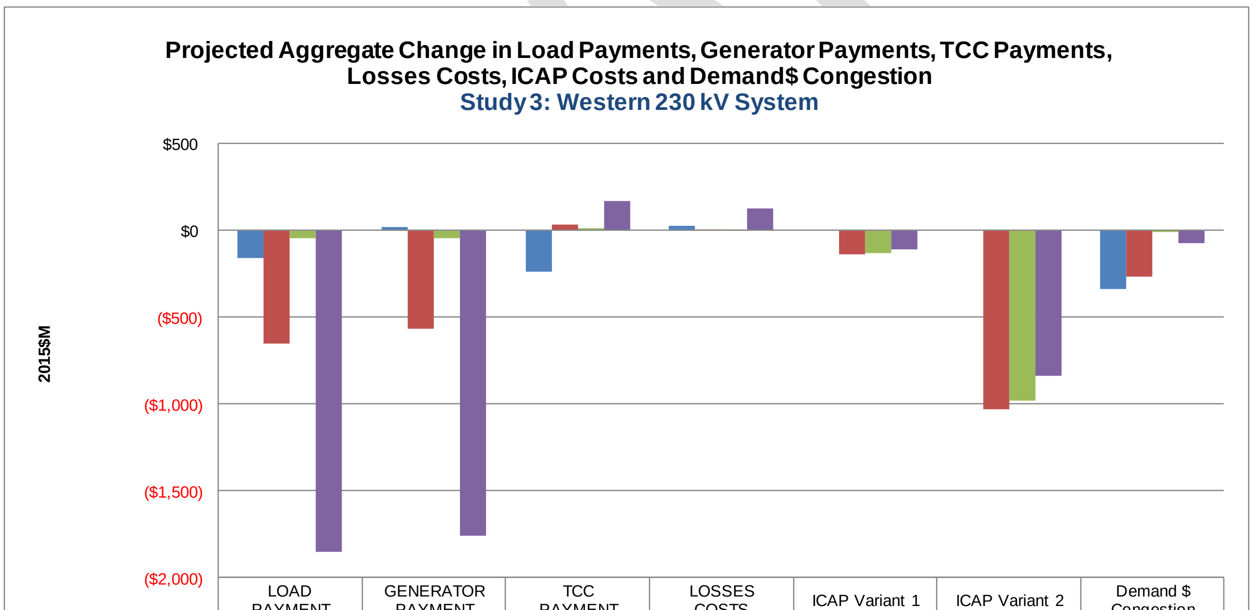
	LOAD PAYMENT	GENERATOR PAYMENT	TCC PAYMENT	LOSSES COSTS	ICAP Variant 1	ICAP Variant 2	Demand $ Congestion
Transmission	$171	$402	($780)	$0	($377)	($2,797)	($2,479)
Generation	($198)	($57)	($111)	($7)	($859)	($6,255)	($291)
Demand Response	($124)	($55)	($67)	($3)	($832)	($6,117)	($79)
Energy Efficiency	($3,024)	($2,572)	($328)	($75)	($901)	($6,623)	($703)

Figure 5: Changes in Metrics for Study 1 (Aggregated Across Study Period)



	LOAD PAYMENT	GENERATOR PAYMENT	TCC PAYMENT	LOSSES COSTS	ICAP Variant 1	ICAP Variant 2	Demand $ Congestion
Transmission	$133	$285	($634)	($35)	$82	$608	($2,245)
Generation	($57)	($84)	$54	$48	($174)	($1,295)	($208)
Demand Response	($42)	($16)	($25)	($1)	($394)	($2,923)	($3)
Energy Efficiency	($1,466)	($1,270)	($149)	($18)	($447)	($3,310)	($348)

Figure 6: Changes in Metrics for Study 2 (Aggregated Across Study Period)



	LOAD PAYMENT	GENERATOR PAYMENT	TCC PAYMENT	LOSSES COSTS	ICAP Variant 1	ICAP Variant 2	Demand $ Congestion
Transmission	($162)	$21	($238)	$30	$0	$0	($339)
Generation	($655)	($564)	$37	$2	($139)	($1,031)	($265)
Demand Response	($43)	($47)	$14	$1	($132)	($985)	($1)
Energy Efficiency	($1,851)	($1,763)	$172	$125	($112)	($836)	($75)

Figure 7: Changes in Metrics for Study 3 (Aggregated Across Study Period)

Table 2 and Figure 8 present the change in emissions across the ten-year Study Period associated with each of the solutions for each of the studies.

Table 2: Projected Emissions Changes for the Three Studies

Study	Generic Solutions	SO2 Tons	SO2 Cost($M)	CO2 1000Tons	CO2 Cost($M)	NOX Tons	NOX Cost($M)
	Transmission						
Study 1: CE-NS-PV	Edic-New Scotland-Pleasant Valley	9,423	$0.8	2,026	$21.0	3,431	$0.3
Study 2: CE	Edic-New Scotland	7,549	$0.6	1,877	$18.6	3,338	$0.3
Study 3: WEST	Niagara-Gardenville	(8,878)	($0.5)	(4,562)	($46.2)	(1,327)	($0.1)
	Generation						
Study 1: CE-NS-PV	Pleasant Valley	(2,075)	($0.1)	2,465	$27.4	(4,707)	($0.5)
Study 2: CE	New Scotland	(1,601)	($0.0)	1,487	$14.2	(2,145)	($0.2)
Study 3: WEST	Gardenville	(16,942)	($1.1)	(692)	($6.4)	(7,642)	($0.6)
	Demand Response						
Study 1: CE-NS-PV	F (200), G(200), J(800)	(283)	($0.0)	(598)	($5.7)	(799)	($0.1)
Study 2: CE	F (200), G(200), J(200)	(95)	($0.0)	(237)	($2.3)	(321)	($0.0)
Study 3: WEST	A (200), B(200), C(200)	(234)	($0.0)	(207)	($1.8)	(186)	$0.0
	Energy Efficiency						
Study 1: CE-NS-PV	F (200), G(200), J(800)	(2,253)	($0.1)	(16,914)	($149.2)	(6,623)	($0.6)
Study 2: CE	F (200), G(200), J(200)	(342)	$0.0	(8,066)	($72.0)	(2,643)	($0.2)
Study 3: WEST	A (200), B(200), C(200)	(11,193)	($0.9)	(11,520)	($104.5)	(6,826)	($0.7)

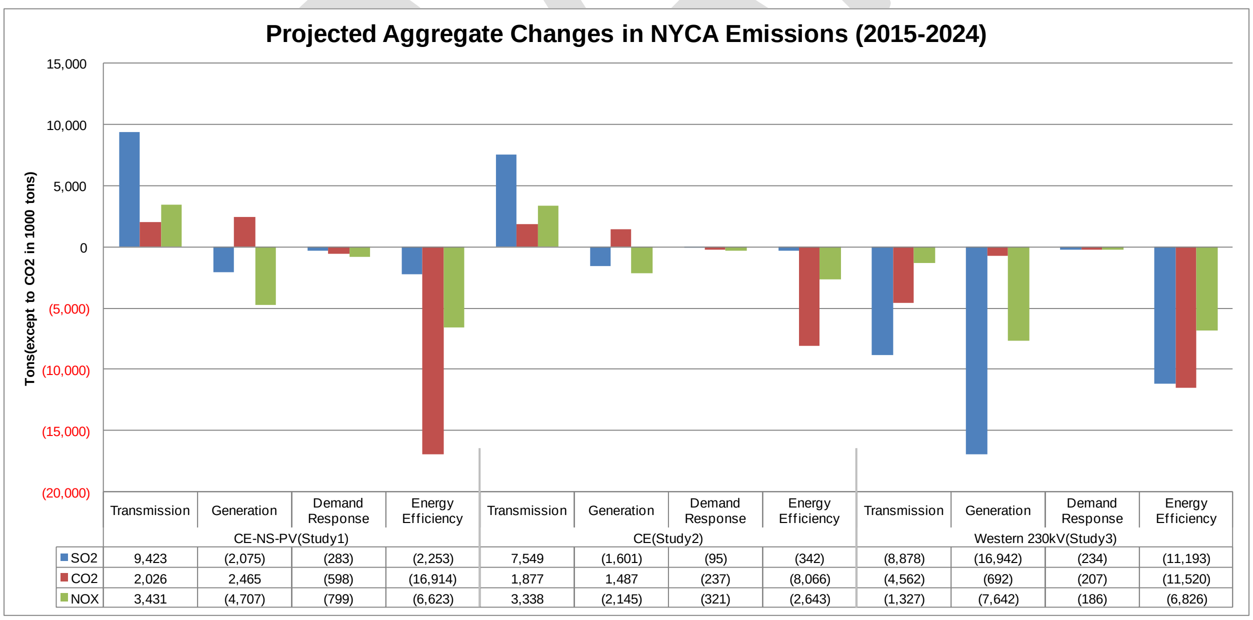


Figure 8: Projected Emissions Changes for Three Studies

C. Scenario Analysis

The NYISO conducted scenario analyses to evaluate the congestion impact of changing variables in the base case assumptions. Scenario analysis provides useful insight on the sensitivity of projected congestion values to differing assumptions included in the base case. Variations in some inputs may provide results that are consistent across NYCA, while other inputs may yield changes that are more localized. The scenarios were selected by the NYISO in collaboration with its stakeholders. They modify the base case to address higher emission costs, higher levels of solar penetration, variations from the base forecasts of electric demand and fuel prices, and the termination of the Athens SPS for the Study Period. These scenarios are each addressed individually; no cumulative impacts are determined.

Table 3 lists major assumptions used for each scenario; and Table 4 shows the cumulative impact on congestion for each scenario for the Study Period in 2015 dollars. Negative values represent a reduction in congestion impact measured by Demand$ Congestion, where Demand$ Congestion is a measure of the congestion component of the LBMP and its impact on NYCA loads. It represents the cost of congestion to consumers.

Table 3: Major Scenario Assumptions

Scenario	Description
Higher Load Forecast	Higher Growth Rate (net increase of 400 GWh from base forecast)
Lower Load Forecast	Lower Growth Rate (net decrease of 170 GWh from base forecast)
Athens SPS Out of Service	2015-2024 (June)
Higher Solar Penetration	3,800 MWs of Solar-PV (distributed state-wide) by 2024; 1.5*base forecast penetration
Higher Natural Gas Prices	Derived from 2015 EIA AEO High Forecast
Lower Natural Gas Prices	Derived from 2015 EIA AEO Low Forecast
Higher CO_2 Emissions Cost	Increased growth rate for CO_2 Allowance Costs (high range of forecasted values)
Double Natural Gas Prices Differential	Midstate & New England / Upstate differential doubled
Half Natural Gas Prices Differential	Midstate & New England / Upstate differential halved

Table 4: Scenarios Impact on Congestion: Ten-Year Study Period ($2015M)

Constraints	Scenarios:(Aggregate Change in Demand$ Congestion from Base Case)(2015 $M)								
	Higher Load Forecast	Lower Load Forecast	Athens SPS Out of Service	High Solar Penetration	Higher Natural Gas Prices	Lower Natural Gas Prices	Higher CO2 Emissions Cost	Double Natural Gas Prices Differential	Half Natural Gas Prices Differential
Central East – New Scotland Pleasant Valley	86	(78)	152	(75)	626	(1,269)	(407)	4,052	(2,643)
Central East	31	(30)	(26)	(65)	604	(1,207)	(375)	4,157	(2,747)
Western 230 kV System	3	(5)	(14)	(5)	(6)	9	14	(1)	(21)

Table 5: Impact on Demand$ Congestion

Constraints	Scenarios:(Aggregate Change in Demand $ Congestion from Base Case)(%)								
	Higher Load Forecast	Lower Load Forecast	Athens SPS Out of Service	High Solar Penetration	Higher Natural Gas Prices	Lower Natural Gas Prices	Higher CO2 Emissions Cost	Double Natural Gas Prices Differential	Half Natural Gas Prices Differential
Central East – New Scotland Pleasant Valley	1.6%	-1.5%	2.8%	-1.4%	11.7%	-23.7%	-7.6%	75.6%	-49.3%
Central East	0.6%	-0.6%	-0.5%	-1.3%	12.2%	-24.4%	-7.6%	83.9%	-55.4%
Western 230 kV System	0.9%	-1.4%	-3.8%	-1.4%	-1.7%	2.5%	3.8%	-0.2%	-5.6%

Tables 4 and 5 above present a summary of how each of the three transmission groupings chosen for study is affected by each of the scenarios for the entire Study Period. As shown, among the scenarios studied, the overall level of natural gas prices and the relative gas prices across the New York Control Area have the greatest impact on the base projection of Demand$ Congestion.

3. Other Findings and Observations

- **Potential Impacts -** This report provides an economic analysis of projected congestion on the New York State bulk power transmission system and the potential costs and benefits of relieving that congestion. The study provides information to interested parties to consider developing transmission, generation, demand response or energy efficiency projects, as appropriate, to relieve congestion, and to propose transmission projects for economic evaluation and potential recovery of costs through the NYISO's Tariff. There are other potential benefits to relieving transmission congestion, such as reduced load payments, increased generator payments, reduced losses, ICAP savings, and reduced emissions that may be of interest to parties in making their investment decisions. For the purposes of this study, the load payment metric does not reflect that loads may be partially hedged through bilateral contracts and ownership of TCCs.

- **Demand$ Congestion** – As with the prior CARIS reports, the level of congestion projected in this 2015 CARIS Phase I Report will be less than historic levels. The disparity in large part is due to certain assumptions, operational parameters and market participant behavior. These disparities include market bidding behavior by both generators and load, virtual transactions that occur in the NYISO Day-Ahead Market, transmission outages, actual commodity price variations and hourly load variations. Similarly, congestion experienced in the future years will differ from the projected values because actual system operating conditions, economic conditions, fuel prices, environmental compliance costs and market behavior will be different from the study assumptions. The purpose of the production simulation model, however, is to help assess the effectiveness of congestion mitigation solutions and analyzes the impacts of these solutions under the same system conditions. The CARIS base case model projects the Demand$ Congestion values in New York at $941 million in 2015 and $1,025 million in 2024. Comparatively, historic Demand$ Congestion values from 2010 to 2014 ranged from a low of $765 million in 2012 to a high of $1,693 million in 2013.

- **Non-Resource Changes Since Last CARIS** – Changes were made in input assumptions and system modeling since the 2013 CARIS. Among the more material changes are:

  a. Explicitly modeling the East of Total East (Zones F-K) Spinning Reserves Requirement (F-K)

  b. Revised Central East operating limits as implemented by NYISO Operations

  c. Reduced transfer limits across UPNY-SENY during thunderstorm alert (TSA) periods using actual 2013 pattern of TSAs

  d. Reduced load forecasts

  e. Revised natural gas price forecasts resulting in lower average price levels but increased price volatility

- **Resource Updates** - The ten-year assessment of future congestion and the potential benefits of relieving some of this congestion are based upon the NYCA resources that were included in the base case for the 2014 Comprehensive Reliability Plan (CRP). No additional updates were incorporated in the 2015 CARIS. However, there were several significant updates from the 2013 CARIS which were captured in the 2014 CRP and which should be noted. These include:

  a. Removal of Market-Based and Reliability-Backstop solutions (necessary to maintain system reliability in 2013 CARIS)

     - Astoria Gas Turbine Repowering (500 MW combined-cycle coupled with removal of 100 MWs in 2016; 500 MW combined-cycle coupled with removal of 495 MWs in 2018)

     - 300 MWs of gas-turbines in G-K in 2021

     - Increase in UPNY-SENY transfer limit of 275 MW in 2022

  b. Danskammer 1-4 were placed back into service in 2014

c. Astoria 2 was placed back into service in 2014

d. Dunkirk 2 was removed beginning in January 2016; Dunkirk 2,3 and 4 were placed back into service on natural gas in September 2016

e. Cayuga 1 and 2 were removed from service as of December 2017

f. Bowline 2 was restored to its full capacity (557 MW) as of July 2015

- **External Load Forecasts –** As in the 2013 CARIS, the NYISO utilized the forecasted values for the external loads and verified that reserve margins were maintained at reasonable levels, *i.e.*, 15%, throughout the Study Period.
- **Scenario Analyses -** Scenario analyses were used to provide projected congestion information associated with variations in load, fuel price, available resources, and other assumptions. The scenario analysis shows the impact on congestion for individual constraints.
- **Specific Solutions Will Produce Different Results -** Projects with characteristics other than the generic projects studied here could also relieve congestion. The generic solutions are representative, and are presented for informational purposes only, but their feasibility was not assessed.
- **Diversity of NYCA Impacts -** This study reports the benefits of relieving congestion both statewide and by zone across New York. All zones do not benefit equally when implementing the generic solutions. For example, load payments decreased in some zones and increased in others.
- **Benefit Lifespan -** The useful life of actual projects may be longer than the ten-year Study Period evaluated in this report pursuant to the NYISO tariff. The useful life of energy efficiency is difficult to measure and will vary with technology. No adjustment was made for potential lifespan differences for energy efficiency relative to actual projects for this analysis. Benefits and costs in later years can be considered in CARIS Phase 2.
- **Study Assumptions** – The study assumptions were developed with Stakeholders subject to the CARIS procedures, based upon the best information available when the database was locked down in May 2015. Different assumptions, based on more recently available data, may impact the study results.

4. Next Steps

Additional Study Requests

Going forward, any interested party can request, at its own expense, an additional study to assess a specific project and its impact on congestion on the New

York bulk power system. The NYISO will conduct the requested studies in the order in which they were accepted and as the NYISO's resource commitments allow.

Specific Project Analysis

Phase 2 of the CARIS process is expected to begin in January 2016, subject to the approval of this 2015 CARIS Phase 1 report by the NYISO Board of Directors. In Phase 2, developers are encouraged to propose projects to alleviate the identified congestion. The NYISO will evaluate proposed specific economic transmission projects upon a developer's request to determine the extent such projects alleviate congestion, and whether the projected economic benefits would make the project eligible for cost recovery under the NYISO's Tariff. While the eligibility criterion is production cost savings, zonal LBMP load savings (net of TCC revenues and bilateral contracts) is the metric used in Phase 2 for the identification of beneficiary savings and the determinant used for cost allocation to beneficiaries for a transmission project.

For a transmission project to qualify for cost recovery through the NYISO's Tariff, the project has to have:

a. a capital cost of at least $25 million,

b. benefits that outweigh costs over the first ten years of operation, and

c. received approval to proceed from 80% or more of the actual votes cast by beneficiaries on a weighted basis.

Subsequent to meeting these conditions, the developer will be able to obtain cost recovery of their transmission project through the NYISO's Tariff, subject to the developer's filing with the Federal Energy Regulatory Commission (FERC) for approval of the project costs and rate treatment.

1. Introduction

Pursuant to Attachment Y of its Open Access Transmission Tariff (OATT, or the Tariff), the NYISO performed the first phase of the 2015 Congestion Assessment and Resource Integration Study (CARIS). The study assesses both historic[6] and projected congestion on the New York bulk power system and estimates the economic benefits of relieving congestion. The CARIS is the primary component of the NYISO's Economic Planning Process (EPP) which is one of the three processes that now comprise the NYISO's Comprehensive System Planning Process (CSPP) (see Figure 1-1). Both the EPP and the Public Policy Transmission Planning Process (PPTPP) utilize inputs from the Reliability Planning Process (RPP). The 2015 CARIS followed on the completion of the 2014 Reliability Needs Assessment (RNA) and Comprehensive Reliability Plan (CRP). In future CARIS cycles, the study assumptions will be developed based on the RNA Base case and proposed reliability solutions, if any are required, determined to be viable and sufficient in the first phase of the CRP.

CARIS consists of two phases: Phase 1 (the Study Phase), and Phase 2 (the Project Phase). Phase 1 is initiated after the NYISO Board of Directors (Board) approves the Comprehensive Reliability Plan (CRP). In Phase 1, the NYISO, in collaboration with its stakeholders and other interested parties, develops a ten-year projection of congestion and together with historic congestion identifies, ranks, and groups the most congested elements on the New York bulk power system. For the top three congested elements or groupings, studies are performed which include: (a) the development of four types of generic solutions to mitigate the identified congestion; (b) a benefit/cost assessment of each solution based on projected New York Control Area (NYCA)-wide production cost savings and estimated project costs; and (c) presentation of additional metrics for informational purposes. The four types of generic solutions are transmission, generation, energy efficiency and demand response. Scenario analyses are also performed to help identify factors that increase, decrease or produce congestion in the CARIS base case.

This final report presents the 2015 CARIS Phase 1 study results and provides objective information on the nature of congestion in the NYCA. Developers can use this information to decide whether to proceed with transmission, generation, or demand response projects. Developers of such projects may choose to pursue them on a merchant basis, or to enter into bi-lateral contracts with LSEs or other parties**.** This report does not make recommendations for specific projects, and does not advocate any specific type of resource addition or other actions.

Developers may propose economic transmission projects for regulated cost recovery under the NYISO's Tariff and proceed through the Project Phase, CARIS Phase 2, which will be conducted by the NYISO upon request and payment by a Developer. Developers of all other projects can request that the NYISO conduct an

[6] The NYISO began reporting NYISO historic congestion information in 2003.

additional CARIS analysis at the Developer's cost to be used for the Developer's purposes, including for use in an Article VII, Article X or other regulatory proceedings. For a transmission project, the NYISO will determine whether it qualifies for regulated cost recovery under the Tariff. Under CARIS, to be eligible for regulated cost recovery, an economic transmission project must have production cost savings greater than the project cost (expressed as having a benefit to cost ratio (B/C) greater than1.0), a cost of at least $25 million, and be approved by at least 80% of the weighted vote cast by New York's Load Serving Entities (LSEs) that serve loads in Load Zones that the NYISO identifies as beneficiaries of the transmission project. The beneficiaries are those Load Zones that experience net benefits measured over the first ten years from the proposed project commercial operation date. After the necessary approvals, regulated economic transmission projects are eligible to receive cost recovery from these beneficiaries through the NYISO Tariff provisions once they are placed in service.

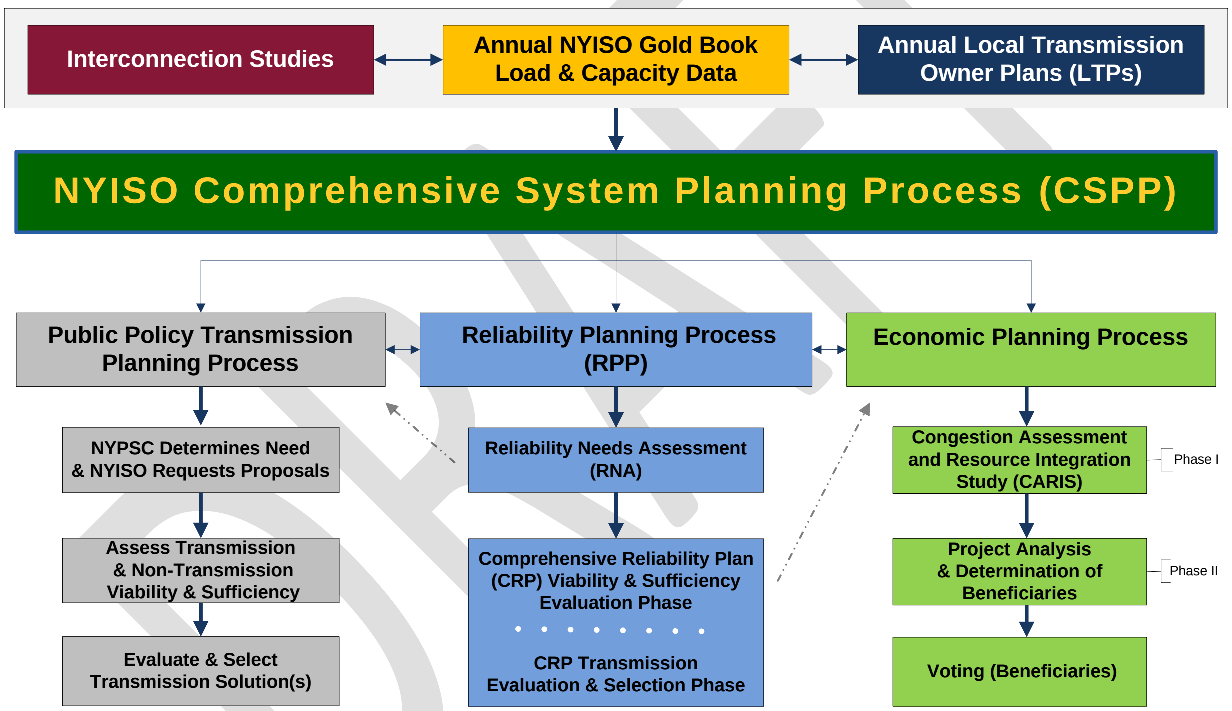


Figure 1-1: NYISO Comprehensive System Planning Process

This 2015 CARIS Phase 1 study includes intended enhancements to the 2013 CARIS Phase 1 study with respect to assumptions, modeling, and methodology for evaluating benefits. Such enhancements were discussed with ESPWG. Some of these changes reflect actual system changes while others are improvements. For example, the system topology was modified to include the Transmission Owner Transmission Solutions (TOTS), consisting of transmission upgrades along the Marcy South path and in Staten Island. In addition, conforming changes were made to the model algorithm which sets the Central East voltage limit to reflect the changes implemented in 2014 in the logic utilized in the NYISO's commitment and dispatch software.

The projected congestion in this report will be different than the actual congestion experienced in the future. CARIS simulations are based upon a limited set of long term assumptions for modeling of grid resources throughout the ten-year planning horizon. A range of cost estimates was used to calculate the cost of generic solution projects (transmission, generation, demand response, and energy efficiency). These costs are intended for illustrative purposes only and are not based on any feasibility analyses. Each of the generic solution costs are utilized in the development of benefit/cost ratios.

The NYISO Staff presented the Phase 1 Study results in a written draft report to the ESPWG and the Transmission Planning Advisory Subcommittee (TPAS) for review. After that review, the draft report was presented to the NYISO's Business Issues Committee (BIC) and the Management Committee (MC) for discussion and action before it was submitted to the NYISO's Board of Directors for approval.

2. Background

2.1. Congestion Assessment and Resource Integration Study (CARIS) Process

The objectives of the CARIS economic planning process are to:

a. Project congestion on the New York State Bulk Power Transmission Facilities (BPTFs) over the ten-year CSPP planning horizon;

b. Identify, through the development of appropriate scenarios, factors that might affect congestion;

c. Provide information to Market Participants, stakeholders and other interested parties on solutions to reduce congestion and to create production cost savings which are measured in accordance with the Tariff requirements;

d. Provide an opportunity for Developers to propose solutions that may reduce the congestion; and

e. Provide a process for the evaluation and approval of regulated economic transmission projects for regulated cost recovery under the NYISO Tariff.

These objectives are achieved through the two phases of the CARIS process which are graphically depicted in Figure 2-1 below.

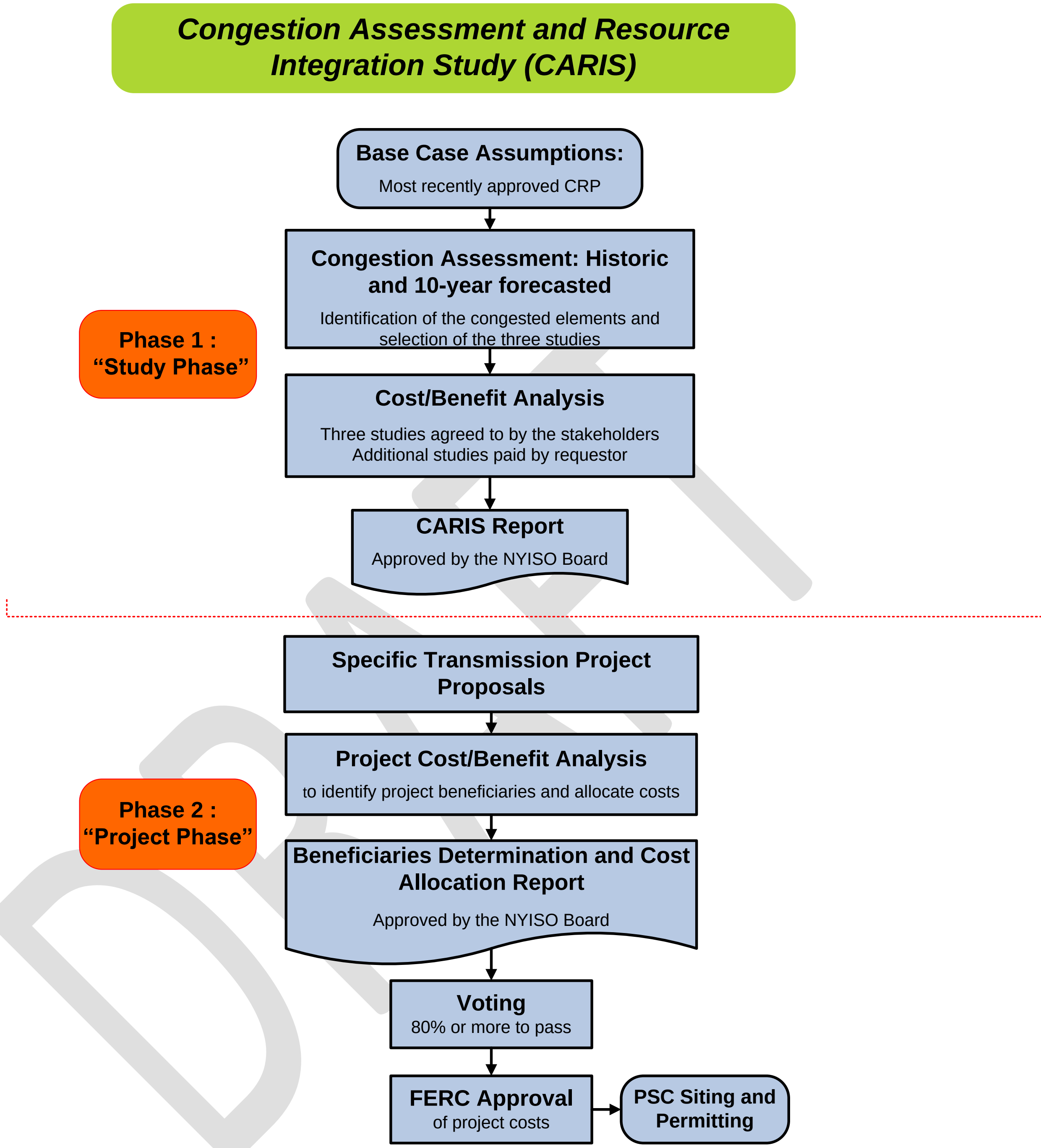


Figure 2-1: Overall CARIS Diagram

2.1.1. Phase 1 - Study Phase

In Phase 1 of the CARIS process, the NYISO, in collaboration with Market Participants, identifies the most congested elements in the New York bulk power system and conducts three transmission congestion studies based on those elements. In identifying the most congested elements, the NYISO performs both a five-year historic and a ten-year forward-looking congestion assessment to identify the most congested elements and, through a relaxation process, develops potential groupings and rankings based on the highest projected production cost savings resulting from the relaxation. The top three ranked elements or groupings become the subjects of the three CARIS studies. For each of these three studies the NYISO conducts a benefit/cost analysis of generic solutions. All resource types - generation, transmission, demand response, and energy efficiency - are considered on a comparable basis as generic solutions to congestion. The solutions analyzed are not specific projects, but rather represent generic transmission, generation, demand response, and energy efficiency resources placed individually in the congested locations on the system to calculate their effects on relieving each of the three most congested elements and the resulting economic benefits.

The principal metric for measuring the economic benefits of each generic solution is the NYCA-wide production cost savings that would result from each generic solution, expressed as the present value over the ten-year planning horizon. The CARIS report also presents data on additional metrics, including estimates of reductions in losses, changes in Locational Based Marginal Pricing (LBMP) load payments, generator payments, changes in Installed Capacity costs, changes in emissions costs and changes in payments for Transmission Congestion Contracts (TCCs). The TCC payment metric in Phase 1 is simplified to include congestion rent calculations only, and is different from the TCC revenue metric contained in Phase 2. Each of the CARIS metrics is described in more detail in Section 3.

The NYISO also conducts scenario analyses to assess the congestion impact of various changes to base case assumptions. Scenario results are presented as the change in system congestion on the three study elements or groupings, as well as other constraints throughout NYCA.

2.1.2. Phase 2 – Regulated Economic Transmission Project (RETP) Cost Allocation Phase

The Phase 2 model will be developed from the CARIS 1 database using an assumption matrix developed after discussion with ESPWG. The Phase 2 database will be updated, consistent with the CARIS manual, to reflect all appropriate and agreed upon system modeling changes required for a 10 year extension of the model. Updating and extending the CARIS database for Phase 2 of the CARIS is conducted after the approval of the CARIS Phase 1 report by the NYISO Board.

Developers of potential economic transmission projects that have an estimated capital cost in excess of $25 million may seek regulated cost recovery through the NYISO Tariff. Such Developers must submit their projects to the NYISO for a benefit/cost analysis in accordance with the Tariff. The costs for the benefit/cost analysis will be supplied by the Developer of the project as required by the Tariff. Projects may be eligible for regulated cost recovery only if the present value of the NYCA-wide production cost savings exceeds the present value of the costs over the first ten years of the project life. In addition, the present value over the first ten years of LBMP load savings, net of TCC revenues and bilateral contract quantities, must be greater than the present value of the projected project cost revenue requirements for the first ten years of the amortization period.

Beneficiaries will be LSEs in Load Zones determined to benefit economically from the project, and cost allocation among those Load Zones will be based upon their relative economic benefit. The beneficiary determination for cost allocation purposes will be based upon each zone's net LBMP load savings. The net LBMP load savings are determined by adjusting the LBMP load savings to account for TCC revenues and bilateral contract quantities; all LSEs in the zones with positive net LBMP load savings are considered to be beneficiaries. The net LBMP load savings produced by a project over the first ten years of commercial operation will be measured and compared on a net present value basis with the project's revenue requirements over the same first ten years of a project's life measured from its expected in-service date. LSE costs within a zone will be allocated according to each LSE's zonal MWh load ratio share.

In addition to the NYCA-wide production cost savings metric and the net LBMP load savings metric, the NYISO will also provide additional metrics, for information purposes only, to estimate the potential benefits of the proposed project and to allow LSEs to consider other metrics when evaluating or comparing potential projects. These additional metrics will include estimates of reductions in losses, changes in LBMP load payments, changes in generator payments, changes in Installed Capacity (ICAP) costs, changes in emissions costs, and changes in TCC revenues. The TCC revenue metric that will be used in Phase 2 of the CARIS process is different from the TCC payment metric used in Phase 1. In Phase 2, the TCC revenue metric will measure reductions in estimated TCC auction revenues and allocation of congestion rents to the TOs (for more detail on this metric see Section 3.2.2 of this report and the Economic Planning Process Manual - Congestion Assessment and Resource Integration Studies Manual[7].)

The NYISO will also analyze and present additional information by conducting scenario analyses, at the request of the Developer after discussions with ESPWG, regarding future uncertainties such as possible changes in load forecasts, fuel prices and environmental regulations, as well as other qualitative impacts such as improved system operations, other environmental impacts, and integration of renewable or other resources. Although this data may assist and influence how a benefiting LSE votes on a project, it will not be used for purposes of cost allocation.

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[7]See http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Planning/epp_caris_mnl.pdf

The NYISO will provide its benefit/cost analysis and beneficiary determination for particular projects to the ESPWG for comment. Following that review, the NYISO benefit/cost analysis and beneficiary determination will be forwarded to the BIC and MC for discussion and action. Thereafter the benefit/cost analysis and beneficiary determination will be forwarded to the NYISO Board of Directors for review and approval.

After the project benefit/cost and beneficiary determinations are approved by the NYISO Board of Directors and posted on the NYISO's website, the project will be brought to a special meeting of the beneficiary LSEs for an approval vote, utilizing the approved voting procedure (See Section 3.3.5 of the Economic Planning Process Manual - Congestion Assessment and Resource Integration Studies Manual). The specific provisions for cost allocation are set forth in the Tariff. In order for a project to be approved for regulated cost recovery, the Tariff states that "eighty (80) percent or more of the actual votes cast on a weighted basis must be cast in favor of implementing the project." If the project meets the required vote in favor of implementing the project, and the project is implemented, all beneficiaries, including those voting "no," will pay their proportional share of the cost of the project through the NYISO Tariff. This process will not relieve the Developer of the responsibility to file with FERC for approval of the project costs which were presented by the Developer to the voting beneficiaries and with the appropriate state authorities to obtain siting and permitting approval for the project.

3. CARIS Methodology and Metrics

3.1. CARIS Methodology

For the purposes of conducting the ten-year forward looking CARIS analysis, the NYISO, in conjunction with ESPWG, developed a production costing model database and utilized GE's Multi-Area Production Simulation (MAPS) software. The details and assumptions in developing this database are summarized in Appendix C.

Since 2012, the NYISO has utilized an off-line version of the NYISO's production Security Constrained Unit Commitment software (SCUC), entitled Congestion Reporting for Off-Line SCUC (CROS), to perform its historic congestion analyses. CARIS utilizes the most recent five years of historic data. Unlike MAPS simulation, CROS recognizes historic virtual bidding and transmission outages and calculates production costs based on mitigated generation bids. While those additional attributes are important in capturing the real congestion costs for the past events, it is nearly impossible to model them with certainty in projecting future transmission congestion. Therefore, these attributes are not accounted for in the ten-year forward looking CARIS analysis. Actual future congestion will vary from projections depending on a number of factors. For more detail see Appendix D.

3.2. CARIS Metrics

The principal benefit metric for CARIS Study Phase analysis is the NYCA-wide production cost savings that would result from each of the generic solutions. Additional benefit metrics were analyzed as well, and the results are presented in this report and accompanying appendices for informational purposes only. All benefit metrics were determined by measuring the difference between the projected CARIS base case value and a projected solution case value when each generic solution was added. The discount rate of 6.843% used for the present value analysis was the current weighted average cost of capital for the NYTOs, weighted by their annual GWh load in 2014.

One of the key metrics in the CARIS analysis is termed Demand Dollar congestion (Demand$ Congestion). Demand$ Congestion represents the congestion component of load payments which ultimately represents the cost of congestion to consumers. For a Load Zone, the Demand$ Congestion of a constraint is the product of the constraint shadow price, the Load Zone shift factor (SF) on that constraint, and the zonal load. For NYCA, the Demand$ Congestion is the sum of all of the zonal Demand$ Congestion.

These definitions are consistent with what has been used for the reporting of historic congestion for the past eleven years. Demand$ Congestion is used to identify and rank the significant transmission constraints as candidates for grouping and the evaluation of potential generic solutions. It does not equate to payments by load.

3.2.1. Principal Benefit Metric[8]

The principal benefit metric for the CARIS Study Phase analysis is the present value of the NYCA-wide production cost savings that are projected to result from implementation of each of the generic congestion mitigation solutions. The NYCA-wide production cost savings are calculated as those savings associated with generation resources in the NYCA and the costs of incremental imports/exports priced at external proxy generator buses of the solution case. This is consistent with the methodology utilized in the 2011 and 2013 CARIS cycles. Specifically, the NYCA-wide production cost savings are calculated using the following formula:

NYCA-wide Production Cost Savings =

NYCA Generator Production Cost Savings -

$$\sum \left[(\textit{Import/Export Flow})_{Solution} - (\textit{Import/Export Flow})_{Base}\right] \times \textit{ProxyLMP}_{Solution}$$

Where:

$\textit{ProxyLMP}_{Solution}$ is the LMP at one of the external proxy buses;

$(\textit{Import/Export Flow})_{Solution} - (\textit{Import/Export Flow})_{Base}$ represents incremental imports/exports with respect to one of the external systems; and the summations are made for each external area for all simulated hours.

3.2.2. Additional Benefit Metrics

The additional benefits, which are provided for information purposes only, include estimates of reduction in loss payments, LBMP load costs, generator payments, ICAP costs, emission costs, and TCC payments. All the quantities, except ICAP, will be the result of the forward looking production cost simulation for the ten-year planning period. The NYISO, in collaboration with the ESPWG, determined the additional informational metrics to be defined for this CARIS cycle given existing resources and available data. The collaborative process determined the methodology and models needed to develop and implement these additional metrics requirements, which are described below and detailed in the Economic Planning Process Manual - Congestion Assessment and Resource Integration Studies Manual. An example illustrating the relationship among some of these metrics is provided in Appendix E.

Reduction in Losses – This metric calculates the change in marginal losses payments. Losses payments are based upon the loss component of the zonal LBMP load payments.

LBMP Load Costs – This metric measures the change in total load payments. Total load payments include the LBMP payments (energy, congestion

[8] Section 31.3.1.3.4 of the Tariff specifies the principal benefit metric for the CARIS analysis.

and losses) paid by electricity demand (load, exports, and wheeling). Exports will be consistent with the input assumptions for each neighboring control area.

Generator Payments – This metric measures the change in generation payments by measuring only the LBMP payments (energy, congestion, losses). Thus, total generator payments are calculated for this information metric as the sum of the LBMP payments to NYCA generators and payments for net imports. Imports will be consistent with the input assumptions for each neighboring control area.

ICAP Costs –The latest available information from the installed reserve margin (IRM), locational capacity requirement (LCR), and ICAP Demand Curves are used for the calculation. The NYISO first calculates the NYCA MW impact of the generic solution on LOLE. The NYISO then forecasts the ICAP cost per megawatt-year point on the ICAP demand curves in Rest of State and in each locality for each planning year. There are two variants for calculating this metric, both based on the MW impact. For more detail on this metric see the Section 31.3.1.3.5.6 of the Tariff.

Emission Costs – This metric captures the change in the total cost of emission allowances for CO_2, NO_X, and SO_2, emissions on a zonal basis. Total emission costs are reported separately from the production costs. Emission costs are the product of forecasted total emissions and forecasted allowance prices.

TCC Payments – The TCC payment metric is calculated differently for Phase 1 than it is calculated for Phase 2 of the CARIS process, as described in the NYISO Tariff. The TCC Payment is the change in total congestion rents collected in the day-ahead market. In this CARIS Phase 1, it is calculated as (Demand Congestion Costs + Export Congestion Costs) – (Supply Congestion Costs + Import Congestion Costs). This is not a measure of the Transmission Owners' TCC auction revenues.

4. Baseline System Assumptions

The implementation of the CARIS process requires the gathering, assembling, and coordination of a significant amount of data, in addition to that already developed for the reliability planning processes. The 2015 CARIS study process is conducted by updating the base case input assumptions provided in the 2014 CRP and aligns with the ten-year reliability planning horizon for the 2014 CRP.

4.1. Notable System Assumptions & Modeling Changes

The base case has been updated as of May 1, 2015 for this CARIS Phase 1 using the assumptions provided below. These assumptions were discussed with stakeholders at several meetings of the ESPWG and were used to project future system conditions. Appendix C includes a detailed description of the assumptions utilized in the CARIS analysis. Because assumptions are used in the study, the actual results may differ from those projected in this study. The key assumptions are presented below:

1. The load and capacity forecast was updated using the 2015 Load and Capacity Data Report (Gold Book) baseline forecast for energy and peak demand by zone for the ten year Study Period. New resources and changes in resource capacity ratings were incorporated based on the RNA inclusion rules.

2. The 2014 CRP power flow base cases were utilized without update in the 2015 CARIS study.

3. The transmission and constraint model utilizes a bulk power system representation for most of the Eastern Interconnection as described below. The model uses both the 2014 RNA/CRP transfer limits and actual operating limits.

4. The production cost model performs a security constrained economic dispatch of generation resources to serve the load. The production cost curves, unit heat rates, fuel forecasts and emission costs forecast were developed by the NYISO from multiple data sets including public domain information, proprietary forecasts and confidential market information. The model includes scheduled generation maintenance periods based on a combination of each unit’s planned and forced outage rates.

In addition to the modeling changes listed below that can have significant impacts on the congestion projections, there are both known NYCA events as well as projected events, which were modeled by the NYISO in the base case in accordance with the requirements of the Tariff, that have impacts on the simulation outcome, as summarized in Table 4-1.

Major Modeling Inputs	
Input Parameter	**Change from the 2013 CARIS**
Load Forecast	Lower
Natural Gas Price Forecast	Lower
Carbon Price Forecast	Lower
NOx Price Forecast	Lower
SOx Price Forecast	Lower
Hurdle Rates	PJM & IMO, higher; ISO-NE, lower
Modeling Changes	
Description	**Change from the 2013 CARIS**
MAPS Software Upgrades	Latest GE MAPS Version 13.2 06/11/15 Release was used for production cost simulation.
Central East Interface Limit	The nomogram to determine the voltage limit based on the commitment of Athens and the Oswego complex units was revised to reflect the updated SCUC algorithm. [9]
Ramapo PARs	Modeling algorithm was adjusted to reflect that 80% of Rockland Electric (RECO) load be served across the Ramapo PARS, per the PJM-NYISO Joint Operating Agreement.
Fuel price forecast	Enhanced the forecast methodology to incorporate more appropriate pattern of natural gas price spikes.
PJM Representation Expanded	Expanded the modeled PJM system to include the East Kentucky Power Cooperative which joined the PJM market in 2013.

[9] The Oswego complex consists of Oswego 5 and 6, Fitzpatrick, Nine Mile 1 and 2, and Sithe Independence. See http://www.nyiso.com/public/webdocs/markets_operations/market_data/power_grid_info/CE_VC_Static_limit_posting.pdf for details on the Central East voltage limit component values.

Table 4-1: Timeline of NYCA Changes

Year	Year-to-Year Changes
2015	Bowline 2 uprate from 183MW to 557MW, 7/1/2015;Dunkirk 2 retired on 12/31/2015
2016	Dunkirk 2, 3 and 4 return to service on natural gas on 9/1/2016; TOTS projects in Service.
2017	Taylor Biomass, 19MW, in-service: 2/1/2017; Cayuga 1 and 2 retired on 12/1/17
2018	No Changes
2019	No Changes
2020	No Changes
2021	No Changes
2022	No Changes
2023	No Changes
2024	Athens SPS, retired on 6/2024

4.2. Load and Capacity Forecast

The load and capacity forecast used in the CARIS base case, provided in Table 4-2, was based on the 2015 Gold Book and accounts for the impact of programs such as the Energy Efficiency Portfolio Standard (EEPS). Appendix C contains similar data, broken out by fuel type, for the modeled external control areas.

Table 4-2: CARIS 1 Base Case Load and Resource Table

		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Peak Load(MW)											
NYCA		33,567	33,636	33,779	33,882	34,119	34,309	34,469	34,639	34,823	35,010
Zone J		11,929	12,013	12,136	12,239	12,329	12,386	12,466	12,550	12,640	12,732
Zone K		5,539	5,506	5,485	5,462	5,470	5,468	5,515	5,567	5,624	5,685
Resources(MW)											
NYCA	Capacity	40,485	40,546	40,650	40,293	41,347	41,347	41,347	41,347	41,347	41,347
	SCR	1,124	1,124	1,124	1,124	1,124	1,124	1,124	1,124	1,124	1,124
	Total	41,610	41,671	41,774	41,417	42,471	42,471	42,471	42,471	42,471	42,471
Zone J	Capacity	10,232	10,232	10,232	10,232	10,232	10,232	10,232	10,232	10,232	10,232
	SCR	369	369	369	369	369	369	369	369	369	369
	Total	10,602	10,602	10,602	10,602	10,602	10,602	10,602	10,602	10,602	10,602
Zone K	Capacity	6,037	6,037	6,037	6,037	6,037	6,037	6,037	6,037	6,037	6,037
	SCR	69	69	69	69	69	69	69	69	69	69
	Total	6,106	6,106	6,106	6,106	6,106	6,106	6,106	6,106	6,106	6,106

Source: 2015 Gold Book baseline load forecasts from Section I.[10]

[10] NYCA "Capacity" values include resources internal to New York, additions, re-ratings, retirements, purchases and sales, and UDRs as presented in the 2015 Gold Book. Zones J and K capacity values include UDRs for the entire capacity of the controllable lines consistent with the 2014 RNA.

4.3. Transmission Model

The CARIS production cost analysis utilizes a bulk power system representation for the entire Eastern Interconnection, which is defined roughly as the bulk electric network in the United States and Canadian Provinces East of the Rocky Mountains, excluding WECC, and Texas. Figure 4-1 below illustrates the NERC Regions and Balancing Authorities in the CARIS model. The CARIS model includes a full active representation for the NYCA, ISO-NE, IESO, and PJM.

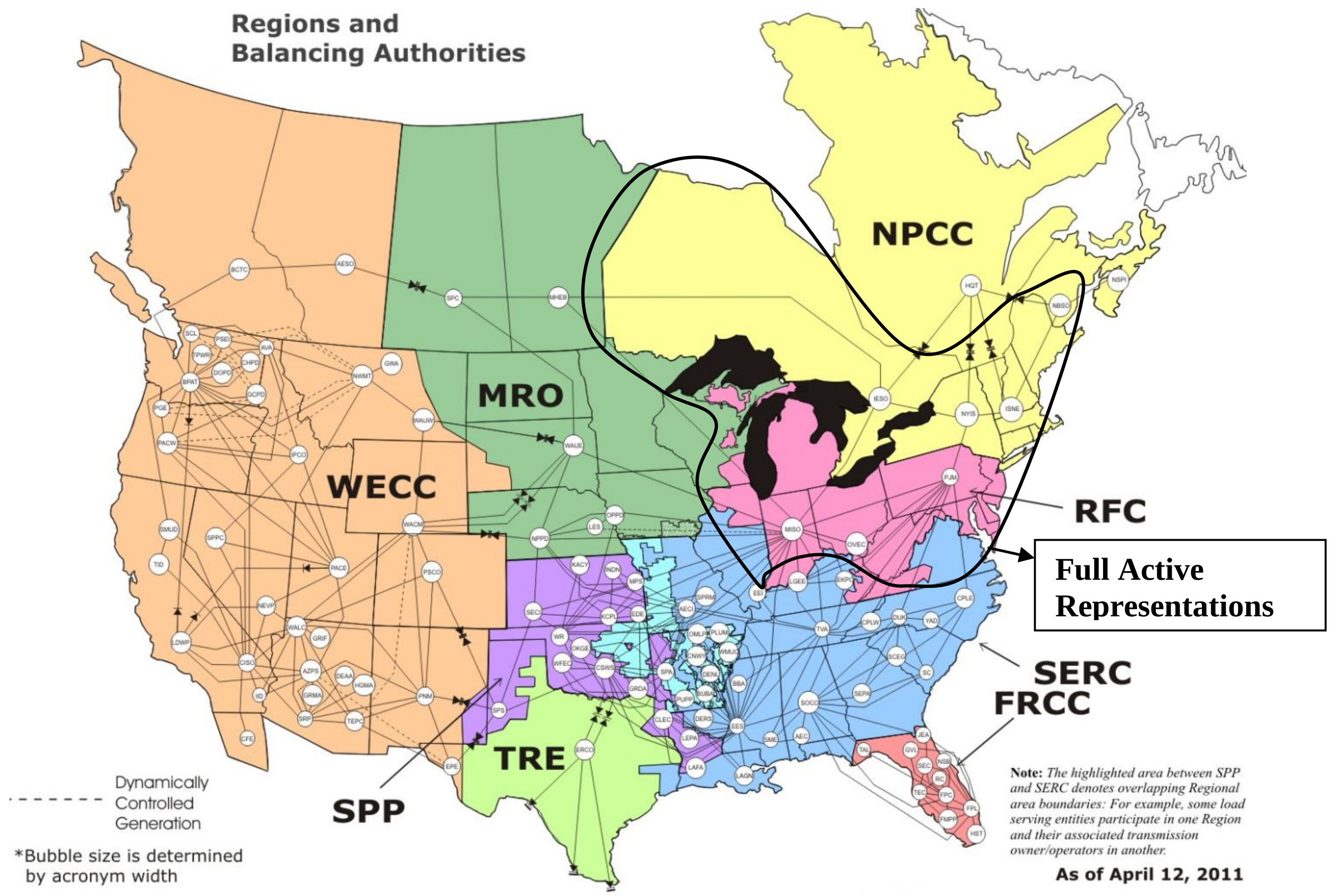

Figure 4-1: Areas Modeled in CARIS (Excluding WECC, FRCC, SPP, & TRE)

Source: NERC

4.3.1. New York Control Area Transfer Limits

CARIS utilizes normal transfer criteria for MAPS simulations for production costing, but it adopts emergency transfer criteria for MARS simulations in order to determine the changes in NYCA and locational reserve margins due to each of the modeled solutions for the purpose of calculating an ICAP metric. Normal thermal interface transfer limits for the CARIS study are not directly utilized from the thermal transfer analysis performed using the Power Technologies Inc. Managing and Utilizing System Transmission (MUST) or PowerGEM's Transmission Adequacy & Reliability Assessment (TARA) software application. Instead, CARIS uses the most limiting monitored lines and contingency sets identified from either MUST/TARA analysis or historical binding constraints.

For voltage and stability based limits the normal and emergency limits are assumed to be the same. For NYCA interface stability transfer limits, the limits are consistent with the operating limits[11]. Central East was modeled with a unit sensitive nomogram reflective of the algorithm utilized by NYISO Operations.[12] Modeling of transmission owner transmission solutions (TOTS) decreases Central East voltage limit by 150MW, which is consistent with the 2014 RNA/CRP.

4.4. Fuel Forecasts

4.4.1. CARIS Base Annual Forecast

The fuel price forecasts for CARIS are based on the U.S. Energy Information Administration's (EIA)[13] current national long-term forecast of delivered fuel prices, which is released each spring as part of the Annual Energy Outlook (AEO). The figures in this forecast are in nominal dollars.

4.4.2. New York Fuel Forecast

In developing the New York fuel forecast, adjustments were made to the EIA fuel forecast to reflect bases for fuel prices in New York. Key sources of data for estimating the relative differences or 'basis' for fuel-oil and coal prices in New York are the Monthly Utility and non-Utility Fuel Receipts and Fuel Quality Data reports based on the information collected through Form EIA-923.[14] The regional bases for natural gas prices are based on a comparative analysis of monthly national delivered prices published in EIA's Short Term Energy Outlook (STEO) and spot prices for selected trading hubs. The base annual forecast series from the AEO are then subjected to an adjustment to reflect the New York 'basis' relative to the national prices as described below.

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11 http://www.nyiso.com/public/webdocs/markets_operations/market_data/reports_info/operating_studies/NYISO_InterfaceLimtsandOperatingStudies.pdf

12 http://www.nyiso.com/public/webdocs/markets_operations/market_data/power_grid_info/CE_VC_Static_limit_posting.pdf

13 www.eia.doe.gov

14 Prior to 2008, this data was submitted via FERC Form 423. 2008 onwards, the same data are collected on Schedule 2 of the new Form EIA-923. See http://www.eia.doe.gov/cneaf/electricity/page/ferc423.html . These figures are published in Electric Power Monthly.

Natural Gas

Analysis of EIA's Short-Term Energy Outlooks from the past five years for the national average of delivered price of natural gas for electricity generation suggests that it is around 10% higher than Henry Hub prices. The forecasted regional differential, that is, the differential between the regional natural gas and the national average, is calculated as the 3-year weighted-average of the difference between the historic regional price and 110% of Henry Hub prices.[15] The natural gas price for "Downstate" (Zones J and K), is the Transco Zone 6 (New York) hub-price[16], for "Midstate" (Zone F through I), is Tennessee Zone 6, and for "Upstate" (Zones A through E) the proxy-hub is the Tetco-M3. As of January 2015, the forecasted Downstate natural gas price is roughly 6% lower relative to the national average, the Midstate natural gas price is 15% higher than the national average and the Upstate natural gas price is 19% lower than the national average. Forecasted fuel prices for Upstate, Midstate and Downstate New York are shown in Figures 4-2, 4-3 and 4-4.

Fuel Oil

Based on EIA forecasts published in its Electric Power Projections by Electricity Market Module Regions (see AEO 2015, Reference Case), price differentials across regions can be explained by a combination of transportation/delivery charges and taxes. Regional bases were calculated based on the relative differences between EIA's national and regional forecasts of Distillate (Fuel Oil No. 2) and Residual (Fuel Oil No. 6) prices. This analysis suggests that for Downstate New York, Distillate Oil prices will be around 3% below the national average while Residual prices are forecasted to be 8% higher than the national average. Correspondingly, the Upstate prices are forecasted to be 1% and 10% lower than the national average for Distillate and Residual Oils, respectively. For illustrative purposes, forecasted prices for Distillate Oil (Fuel Oil #2) and for Residual Oil (Fuel Oil #6) are shown in Figures 4-2, 4-3 and 4-4.[17]

[15] In light of the high price volatility observed during winter months, the basis calculation excludes data for January, February, and December.
[16] The raw hub-price is 'burdened' by an appropriate level of local taxes and approvimant delivery charges.
[17] The observed, abnormal pattern of relative distillate and residual fuel oil prices forecasted for 2013 does not materially impact the study results, given the low price of natural gas relative to both fuel oils.

Coal

The data from EIA's Electric Power Projections by Electricity Market Module Regions was also used to arrive at the forecasted basis for coal. Prices in New York are forecasted to be, on average, 30% higher than in the United States as a whole. (The published figures do not make a distinction between the different varieties of coal; *i.e.*, bituminous, sub-bituminous, lignite, etc.).

4.4.3. Seasonality and Volatility

All average monthly fuel prices, with the exception of coal and uranium, display somewhat predictable patterns of fluctuations over a given 12-month period. In order to capture such seasonality, NYISO estimated seasonal-factors using standard statistical methods.[18] The multiplicative factors were applied to the annual forecasts to yield forecasts of average monthly prices.

The 2015 data used to estimate the seasonal factors are as follows:

- Natural Gas: Raw daily prices from ICE (Intercontinental Exchange) for the trading hubs Transco Zone 6 (New York) - as a proxy for Downstate (Zones J and K) – Tennessee Zone 6 – as a proxy for Midstate (Zones F to I) – Tetco-M3 – as a proxy for Upstate (Zones A to E).
- Fuel Oil #2: EIA's average daily prices for New York Harbor Ultra-Low Sulfur No. 2 Diesel Spot Price. CARIS assumes the same seasonality for both types of fuel-oil.

The seasonalized time-series represents the forecasted trend of average monthly prices. Since CARIS uses weekly prices for its analysis, the monthly forecasted prices are interpolated to yield 52 weekly prices for a given year. Furthermore, "'spikes" are layered on these forecasted weekly prices to capture typical intra-month volatility, especially in the winter months. The "spikes" are calculated as 5-year averages of deviations of weekly (weighted-average) spot prices relative to their monthly averages. The "spikes" for a given month are normalized such that they add to zero.

[18] This is a two-step process: First, deviations around a centered 12-month moving average were calculated over the 2008-2012 period; second, the average values of these deviations were normalized to estimate monthly/seasonal factors.

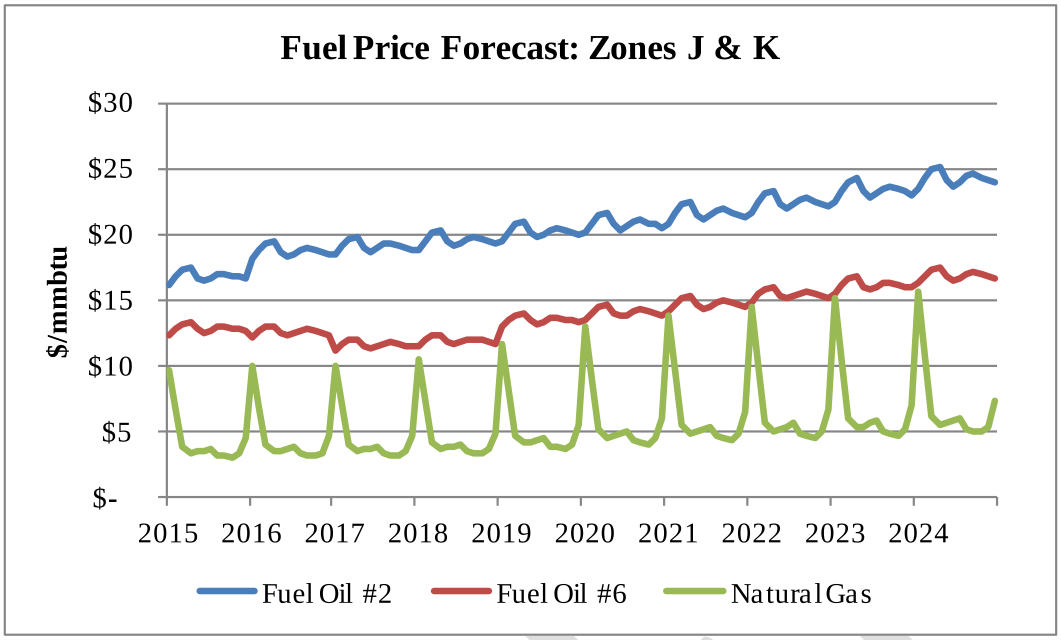


Figure 4-2: Forecasted fuel prices for Zones J & K (nominal $)

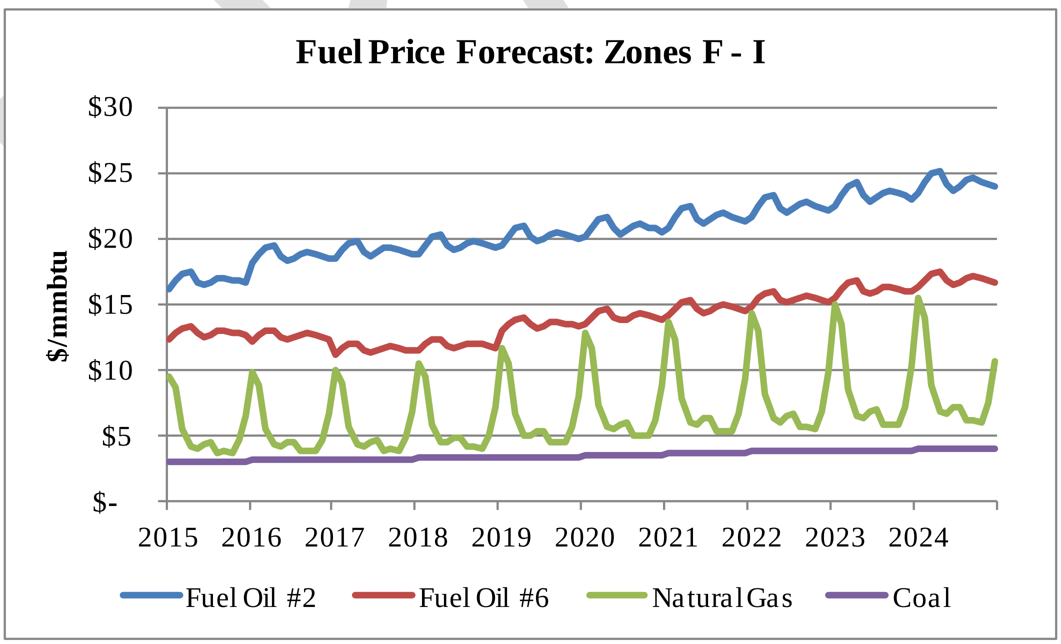


Figure 4-3: Forecasted fuel prices for Zones F-I (nominal $)

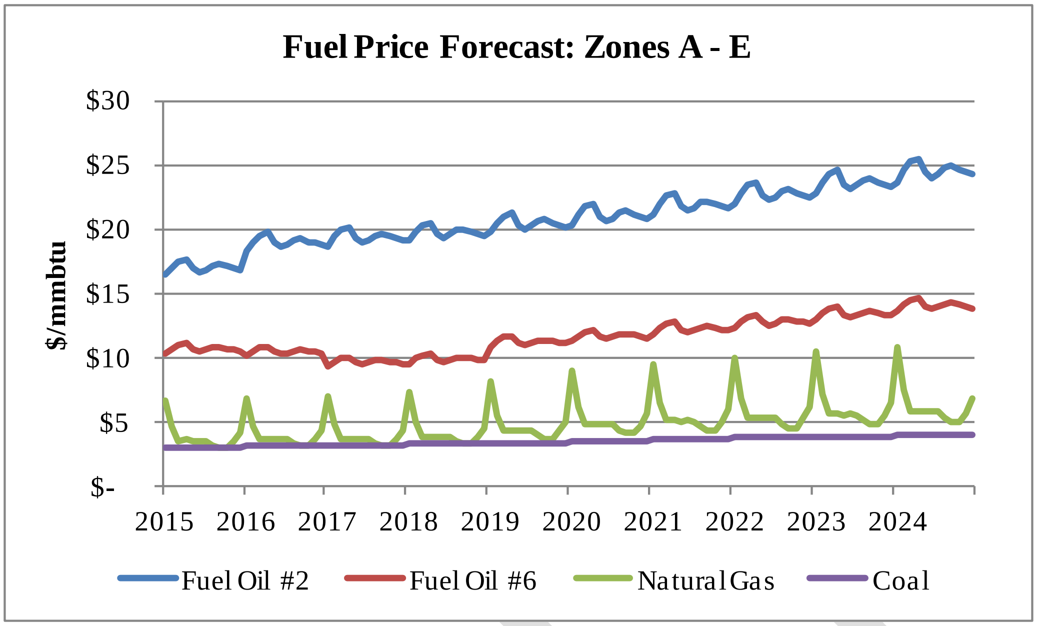


Figure 4-4: Forecasted fuel prices for Zones A-E (nominal $)

4.4.4. External Areas Fuel Forecast

The fuel forecasts for the three external Control Areas, ISO-NE, PJM, and IESO, were also developed. For each of the fuels, the basis for ISO-NE North, ISO-NE South, PJM-East, and PJM-West were based on the EIA data obtained from the same sources as those used for New York. With respect to IESO, the relative price of Natural Gas is based on spot-market data for the Dawn hub obtained from a SNL.[19]

4.5. Emission Cost Forecast

The costs of emission allowances are an increasing portion of generator production costs. Currently, all NYCA fossil fueled generators greater than 25 MW and most generators in many surrounding states are required to hold allowances in amounts equal to their emissions of SO_2, NO_X, and CO_2.

Base Case allowance prices for annual and seasonal NO_X (throughout the Study Period) and SO_2 are developed using representative prices at the time the assumptions are finalized. The CSAPR NO_X and SO_2 allowances prices are adjusted at nominally the same rate as natural gas prices to capture the nominal vs. real value of money while the underlying cost of the allowances decrease over time.

USEPA's Mercury and Air Toxics Standard (MATS), requires reductions in mercury, acid gas, and particulate matter emissions. The standard became effective on

[19] CARIS does not model any Ontario generation as being fueled by either oil or coal.

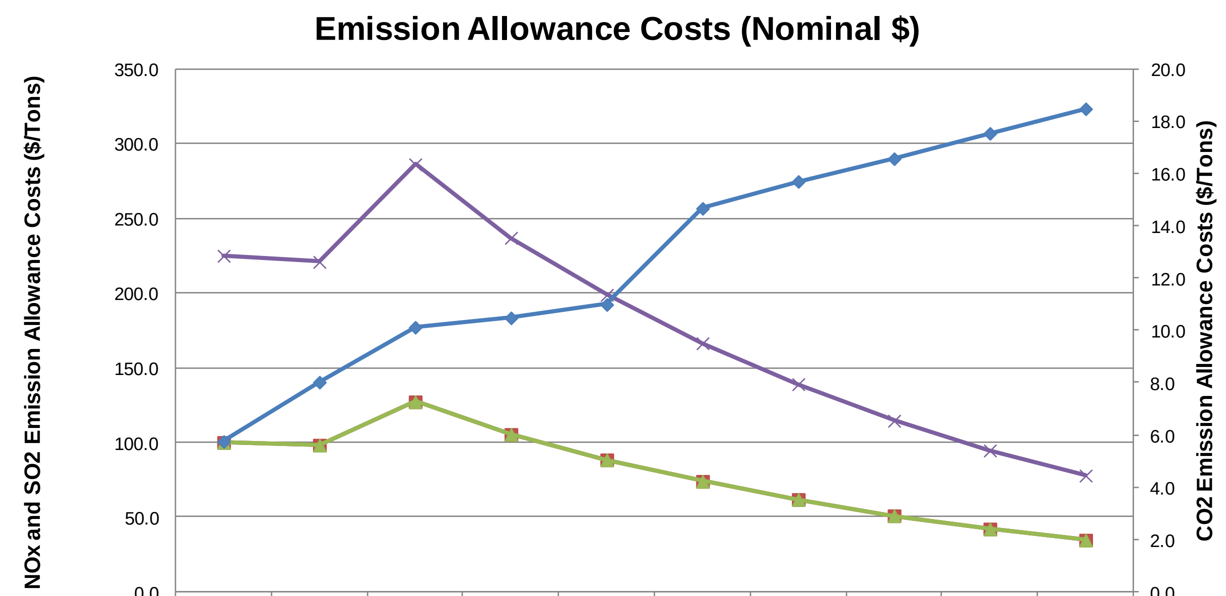
April 16th of 2015 (with the option for an additional year to comply available to most generators). Compliance with the acid gas reduction portion of the standard may be achieved through an alternate SO_2 emission limit. While the rule takes a command and control approach to lowering emissions, USEPA posits in the rulemaking that the majority of the decreases in acid gas emissions required by MATS will be accomplished by the CSAPR SO_2 cap and trade program. For these reasons, USEPA's CSAPR SO_2 price projections are augmented with a $1/MWH cost to cover the incremental operation of control equipment for MATS at coal units beginning in 2016.

The RGGI program for capping CO_2 emissions from power plants includes the six New England states as well as New York, Maryland, and Delaware. Historically the RGGI market has been oversupplied, and prices have remained at the floor. In January 2012 several states, including New York, chose to retire all unsold RGGI allowances from the 2009-2011 compliance period in an effort to reduce the market oversupply. Additionally, RGGI Inc. conducted a mid program review in 2012 which, when became effective in 2014. The emissions cap has been reduced to 91 million tons in 2014 and will decrease to 78 million tons in 2020.

The current cap structure has become binding on the market and therefore the Cost Containment Reserve (CCR) trigger price has been exercised. In 2014, five million additional tons were added to the amount to be auctioned. Current OTC prices are above the CCR trigger price, thus it is likely an additional ten million allowances will be made available for auction in 2015. The allowance price forecast assumes auctions will clear at the CCR trigger price through the study period. Based on a June 2014 draft USEPA proposed rule to limit emissions of CO_2 from existing power plant, this CARIS Study assumed that a federal CO_2 program, similar to the RGGI program, would take effect in 2020. It was assumed that the implementation of the federal CO_2 program would apply to states that are not currently participants in RGGI, as well as the Canadian province of Ontario. The study applies the RGGI allowance price forecast, as described above, to these additional states and Ontario.

For each state, the USEPA proposed rule provided a State Rate Goal for emissions for fossil power plants greater than 25 MW. In August 2015, the Final Rule was released. The final version of the rule provides each state with rate-based and mass-based emission goals. The states have up to three years in which to prepare a State Plan which will be submitted to USEPA for approval. The rule provides a Reliability Safety Valve which can be used to maintain electric system reliability should circumstances arise where emission goals would otherwise be exceeded. The rule also requires a reliability review of the State Plan (SP). The emission limits call for stepwise reductions starting in 2022 and achieving a set standard in 2030. The initial review of the mass-based target for NY is proximate to 2020 RGGI cap. The study assumptions are a general approximation of the Final Rule. The study has not been rerun to reflect the differences with the Final Rule. The NYISO will be an active participant in the development of the SP and restructuring of RGGI.

Figure 4-5 shows the emission allowance forecast by year in \$/Ton.[20]



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
SO2	100.0	98.2	127.2	105.3	88.4	74.0	61.8	50.9	42.1	34.6
Annual NOx	100.0	98.2	127.2	105.3	88.4	74.0	61.8	50.9	42.1	34.6
Ozone NOx	225.0	220.9	286.2	237.0	198.8	166.4	139.0	114.5	94.6	77.8
CO2	5.8	8.0	10.1	10.5	11.0	14.7	15.7	16.6	17.5	18.5

Figure 4-5: Emission Allowance Forecast

4.6. Generic Solutions

Generic solutions are evaluated by NYISO for each of the three CARIS studies utilizing each resource type (generation, transmission, energy efficiency (EE) and demand response (DR)) as required in Section 31.3.1.3.3 of the Tariff. The development of the generic solution representative costs was based on available public information with stakeholder input. This methodology utilized typical MW block size generic solutions, a standard set of assumptions without determining actual project feasibility, and order of magnitude costs for each resource type.

The cost estimates for generic solutions only are intended to set forth an order of magnitude of the potential projects’ costs for Benefit/Cost ratio analysis. These estimates should not be assumed as reflective or predictive of actual projects or imply that facilities can necessarily be built for these estimated costs or in the locations assumed.

[20] Annual NOx prices are used October through May; Ozone NOx prices May through September.

4.6.1. Resource Block Sizes

Typical resource block sizes are developed for each resource type based on the following guidelines:

- Block size would be reflective of a typical size built for the specific resource type and geographic location;
- Block size is to be small enough to be additive with reasonable step changes; and
- Blocks sizes are in comparable proportions between the resource types.

The block sizes selected for each resource type are presented in Table 4-3 through Table 4-5.

Table 4-3: Transmission Block Sizes

Location	Line System Voltage (kV)	Normal Rating (MVA)[21]
Zone F-G	345	1986
Zone A	230	566

Table 4-4: Generation Block Sizes

Plant Location	Plant Block Size Capacity (MW)
Zone A-G	330[22]

Table 4-5: EE and DR Block Sizes

Location	Demand Response Quantity (MW)	Portfolio Type
Zone A-J	200	Energy Efficiency
Zone A-J	200	Demand Response

[21] Solution size for Zones F to G is based on a double-bundled ACSR 1590 KCmil conductor. The amperage is 3324. Solution size for Zone A is based on a single-bundled ACSR 1192.5 KCmil conductor. The amperage is 1422.

[22] Proposed generic unit is a Siemens SGT6-5000F(5).

4.6.2. Guidelines and Assumptions for Generic Solutions

Developing cost estimates for these resource types was dependent on many different parameters and assumptions and without consideration of project feasibility or project-specific costs.

The following guidelines and assumptions were used to select the generic solution:

Transmission Resource

- The generic transmission solution consists of a new transmission line interconnected to the system upstream and downstream of the grouped congested elements being studied.
- The generic transmission line terminates at the nearest existing substations of the grouped congested elements.
- If there is more than one substation located near the grouped congested elements which meets the required criteria, then the two substations that have the shortest distance between the two are selected. Space availability at substations (*i.e.*, room for substation expansion) was not evaluated in this process.

Generation Resource

- The generic generation solution consisted of the construction of a new combined cycle generating plant connecting downstream from the grouped congested elements being studied.
- The generic generation solution terminates at the nearest existing substation of the grouped congested elements.
- If there is more than one substation located near the grouped congested elements which meets the required criteria, the substation that has the highest relative shift factor was selected. Space availability at substations (*i.e.*, room for substation expansion) was not evaluated in this process.
- Total resource increase in MWs should be comparable to MW increase in transfer capability due to transmission solution

Energy Efficiency (EE)

- 200 MW blocks of peak load energy efficiency
- Aggregated at the downstream of the congested elements.
- Limited to whole blocks that total less than 10% of the zonal peak load. If one zone reaches a limit, EE may be added to other downstream zones
- Total resource increase in MWs should be comparable to MW increase in transfer capability due to transmission solution

- **Demand Response (DR)**
- 200 MW demand response modeled at 100 peak hours
- Use the same block sizes in the same locations as energy efficiency

4.6.3 Generic Solution Pricing Considerations

Three sets of cost estimates which were designed to be reflective of the differences in labor, land and permitting costs among Upstate, Downstate and Long Island follow below. The considerations used for estimating costs for the three resource types and for each geographical area are listed in Table 4-6.

Table 4-6: Generic Solution Pricing Considerations

Transmission	Generation	EE	DR
Transmission Line Cost per Mile	Equipment	Energy Efficiency Programs	Demand Response Programs
Substation Terminal Costs	Construction Labor & Materials	Customer Implementation Costs	Customer Implementation Costs
System Upgrade Facilities	Electrical Connection & Substation		
	Electrical System Upgrades		
	Gas Interconnect & Reinforcement		
	Engineering & Design		

Low, mid, and high cost estimates for each element were provided to stakeholders for comment. The transmission costs estimates were reviewed by Market Participants, including Transmission Owners; and the estimated cost data for the mid-point of the generation solutions were taken from the 2013 Demand Curve Reset report. The low and high-point of the generic cost estimates for Energy Efficiency were derived from a study produced on behalf of the New York State Department of Public Service by Industrial Economics and Optimal Energy.[23] Finally, the mid-point of the Demand Response costs was extracted the same report. This establishes a range of cost estimates to address the variability of generic projects. The resulting order of magnitude unit pricing levels are included below in Section 5.4.1. A more detailed discussion of the cost assumptions and calculations is included in Appendix C.

[23] *Final Generic Environmental Impact Statement In CASE 14-M-0101 - Reforming the Energy Vision and CASE 14-M-0094 - Clean Energy Fund,* New York State Department of Public Service, page 4-7.

5. 2015 CARIS Phase 1 Results

This section presents summary level results of the six steps of the 2015 CARIS Phase 1. These six steps include: (1) congestion assessment; (2) ranking of congested elements; (3) selection of three studies; (4) generic solution applications; (5) benefit/cost analysis; and (6) scenario analysis. Study results are described in more detail in Appendix E.

5.1. Congestion Assessment

The CARIS process begins with the development of a ten-year projection of future Demand$ Congestion costs. This projection is combined with the past five years of historic congestion to identify and rank significant and recurring congestion. The results of the historical and future perspective are presented in the following two sections.

In order to assess and identify the most congested elements, both positive and negative congestion on constrained elements are taken into consideration. Whether congestion is positive or negative depends on the choice of the reference point. All metrics are referenced to the Marcy 345 kV bus near Utica, NY. In the absence of losses, any location with LBMP greater than the Marcy LBMP has positive congestion, and any location with LBMP lower than the Marcy LBMP has negative congestion. The negative congestion typically happens due to transmission constraints that prevent lower cost resources from being delivered towards the Marcy bus.

5.1.1. Historic Congestion

Historic congestion assessments have been conducted at the NYISO since 2005 with metrics and procedures developed with the ESPWG and approved by the NYISO Operating Committee. Four congestion metrics were developed to assess historic congestion: Bid-Production Cost (BPC) as the primary metric, Load Payments metric, Generator Payments metric, and Congestion Payment metric. The results of the historic congestion analysis are posted on the NYISO website quarterly. For more information or source of historical results below see:

http://www.nyiso.com/public/markets_operations/services/planning/documents/index.jsp

Historic congestion costs by zone, expressed as Demand$ Congestion, are presented in Table 5-1, indicating that the highest congestion is in New York City and Long Island.

Table 5-1: Historic Demand$ Congestion by Zone 2010-2014 (nominal $M)

Zone	2010	2011	2012	2013	2014
West	$1	$5	$6	$45	$36
Genesee	$6	$6	$3	$11	$9
Central	$11	$10	$8	$38	$38
North	$1	$0	$0	$5	$3
Mohawk Valley	$5	$5	$3	$11	$12
Capital	$62	$47	$34	$143	$149
Hudson Valley	$73	$78	$39	$112	$95
Millwood	$23	$20	$10	$30	$30
Dunwodie	$49	$45	$24	$62	$55
New York City	$561	$549	$261	$639	$531
Long Island	$350	$405	$377	$597	$409
NYCA Total	**$1,140**	**$1,170**	**$765**	**$1,693**	**$1,367**

Notes: Reported values do not deduct TCCs
NYCA totals represent the sum of absolute values
DAM data include Virtual Bidding&planned Transmission outages

Table 5-2 below lists historic congestion costs, expressed as Demand$ Congestion, for the top NYCA constraints from 2010 to 2014. The top congested paths are shown below.

Table 5-2: Historic Demand$ Congestion by Constrained Paths 2010-2014 (nominal $M)

Constraint Path	Historic					Total
	2010	2011	2012	2013	2014	
CENTRAL EAST	$491	$364	$255	$1,089	$1,136	$3,336
DUNWOODIE TO LONG ISLAND	$174	$230	$266	$307	$155	$1,132
LEEDS PLEASANT VALLEY	$232	$165	$137	$138	$42	$715
GREENWOOD	$133	$98	$72	$96	$13	$413
NEW SCOTLAND LEEDS	$33	$196	$9	$27	$9	$273
DUNWOODIE MOTTHAVEN	$52	$88	$22	$18	$40	$219
RAINEY VERNON	$32	$60	$10	$31	$1	$134
E179THST HELLGT ASTORIAE	$20	$40	$11	$16	$3	$90
SHORE_RD 345 SHORE_RD 138 1	$2	$0	$4	$36	$12	$54
EGRDNCTY 138 VALLYSTR 138 1	$3	$7	$8	$14	$20	$52

* Ranking is based on absolute values.

Table 5-3 summarizes the annual historic congestion results posted by the NYISO. NYISO reports the summaries of the calculated changes in the four historic congestion metrics: Bid Production Cost (BPC), Generator Payments, Congestion Payments, and Load Payments. The changes in these four historic congestion metrics were calculated using CROS as the constrained system values minus the unconstrained system values. Positive numbers imply savings while negative numbers imply increases in payments when all constraints are relieved. Unhedged Congestion is calculated as the total congestion represented by Demand$ Congestion minus the TCC hedge payments (TCC auction proceeds). Total payments made by load adjusted for the TCC hedges, TCC shortfalls, and Rate Schedule 1 imbalances comprise the statewide Unhedged Load Payments. These adjusted statewide Unhedged Load Payments equal the total Generator Payments.

Table 5-3: Historic NYCA System Changes – Mitigated Bids 2010-2014 (nominal $M)

Historic NYCA System Changes - Mitigated Bids 2010-2014 (nominal $M)				
Year	Change in BPC	Change in Generator Payments	Change in Unhedged Congestion Payments	Change in TCC Payments
2010	94	(116)	640	515
2011	99	(86)	666	511
2012	106	(55)	457	319
2013	146	(186)	1,066	737
2014	116	(435)	847	645

Figure 5-1 below illustrates a cumulative effect of bid production costs savings over the past five years as a result of relieving all NYCA constraints.

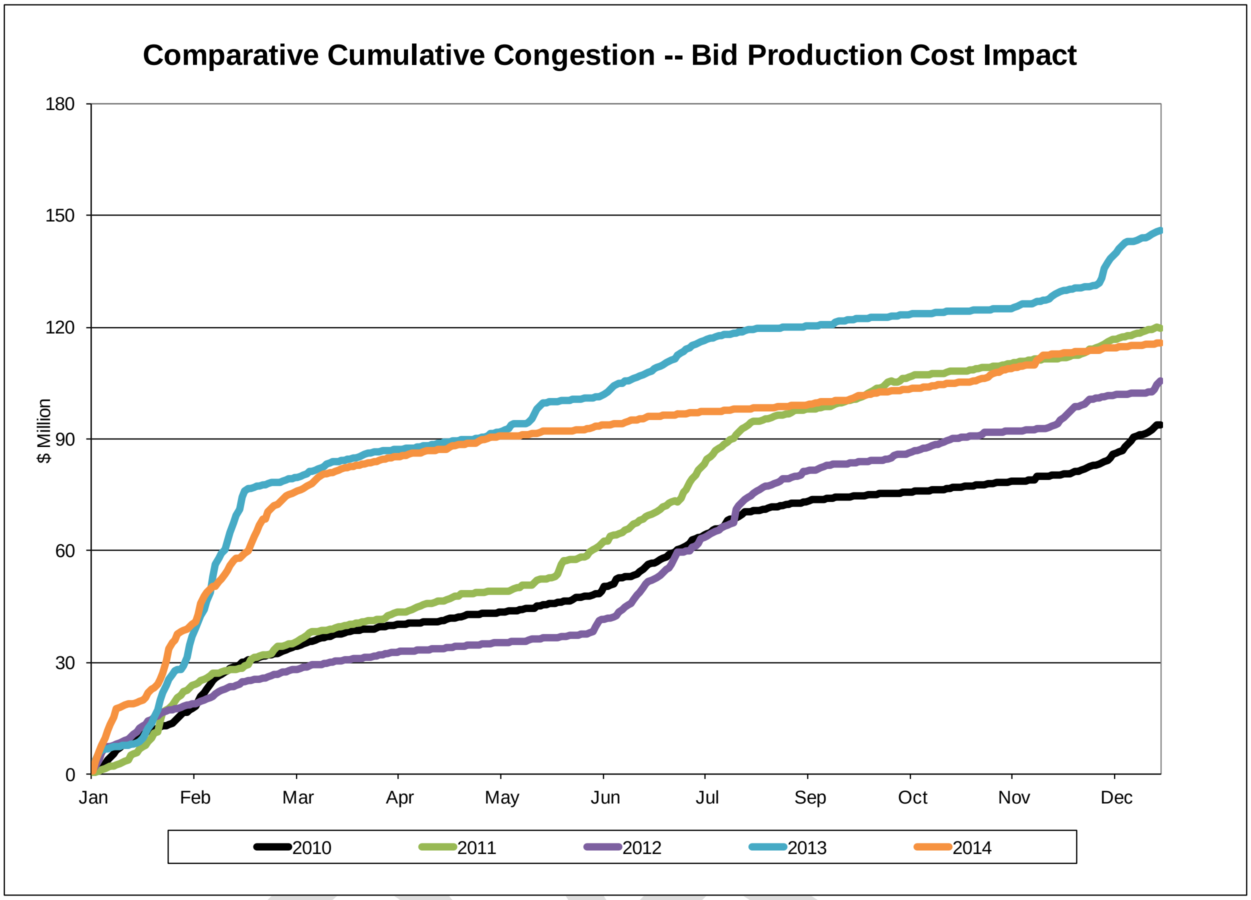


Figure 5-1: Historic Cumulative BPC Savings, 2010-2014 (nominal $M)

5.1.2. Projected Future Congestion

Future congestion for the Study Period was determined from a MAPS simulation using a base case developed with the ESPWG. As reported in Section 3.2, congestion is reported as Demand$ Congestion. MAPS simulations are highly dependent upon many long-term assumptions, each of which affects the study results. The MAPS model utilizes input assumptions listed in Appendix C.

When comparing historic congestion costs to projected congestion costs, it is important to note that there are significant differences in assumptions used by CROS and MAPS. MAPS, unlike CROS, did not simulate the following: (a) virtual bidding; (b) transmission outages; (c) price-capped load; (d) generation and demand bid price; (e) Bid Production Cost Guarantee (BPCG) payments; and (f) co-optimization with ancillary services.

Discussion

Table 5-4 presents the projected congestion from 2015 through 2024 by Load Zone. The relative costs of congestion shown in this table indicate that the majority of the projected congestion is in the Downstate zones – NY City and Long Island. Year to year changes in congestion reflect changes in the model, which are discussed in Section 4.1.

Table 5-4: Projection of Future Demand$ Congestion 2015-2024 by Zone (nominal $M)

Demand Congestion ($M)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
West	$33	$39	$46	$48	$47	$43	$47	$43	$46	$46
Genesee	$6	$4	$5	$4	$5	$4	$4	$4	$4	$4
Central	$18	$15	$17	$17	$20	$14	$14	$14	$15	$15
North	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1
Mohawk Valley	$7	$5	$6	$6	$7	$5	$5	$5	$5	$6
Capital	$103	$101	$114	$110	$130	$96	$98	$94	$100	$98
Hudson Valley	$69	$58	$67	$63	$73	$53	$55	$53	$57	$63
Millwood	$22	$18	$21	$19	$23	$17	$17	$17	$18	$20
Dunwoodie	$44	$36	$41	$39	$45	$33	$34	$33	$36	$42
NY City	$410	$345	$404	$378	$439	$333	$340	$332	$370	$422
Long Island	$230	$205	$229	$226	$251	$210	$236	$251	$275	$310
NYCA Total	**$941**	**$828**	**$951**	**$909**	**$1,040**	**$809**	**$851**	**$846**	**$927**	**$1,025**

Note: Reported costs have not been reduced to reflect TCC hedges and represent absolute values.

Based on the positive Demand$ Congestion costs, the future top congested paths are shown in Table 5-5 below. Table 5-6 presents the historic and projected Demand$ Congestion by constraint.

Table 5-5: Projection of Future Demand$ Congestion 2015-2024 by Constrained Path (nominal $M)

Nominal Value($M)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CENTRAL EAST	$643	$611	$691	$662	$782	$572	$585	$561	$598	$584
DUNWOODIE TO LONG ISLAND	$39	$42	$42	$48	$50	$51	$64	$75	$79	$87
LEEDS PLEASANT VALLEY	$89	$33	$53	$37	$35	$26	$30	$36	$54	$125
GREENWOOD	$19	$19	$25	$21	$24	$28	$23	$25	$28	$35
NEW SCOTLAND LEEDS	$7	$1	$1	$0	$0	$0	$0	$1	$1	$0
PACKARD HUNTLEY	$28	$37	$44	$48	$44	$36	$36	$33	$35	$34
DUNWOODIE MOTTHAVEN	-	-	-	-	-	-	-	-	-	-
RAINEY VERNON	$1	$1	$1	$2	$2	$2	$3	$2	$3	$2
E179THST HELLGT ASTORIAE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
EGRDNCTY 138 VALLYSTR 138 1	$4	$3	$4	$3	$4	$4	$5	$4	$7	$6

*The absolute value of congestion is reported.

Table 5-6: Historic and Projection of Demand$ Congestion 2015-2024 by Constraint (nominal $M)

Constraint Group (Nominal $M)	Historic					Projected									
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CENTRAL EAST	$491	$364	$255	$1,089	$1,136	$643	$611	$691	$662	$782	$572	$585	$561	$598	$584
DUNWOODIE TO LONG ISLAND	$174	$230	$266	$307	$155	$39	$42	$42	$48	$50	$51	$64	$75	$79	$87
LEEDS PLEASANT VALLEY	$232	$165	$137	$138	$42	$89	$33	$53	$37	$35	$26	$30	$36	$54	$125
GREENWOOD	$133	$98	$72	$96	$13	$19	$19	$25	$21	$24	$28	$23	$25	$28	$35
NEW SCOTLAND LEEDS	$33	$196	$9	$27	$9	$7	$1	$1	$0	$0	$0	$0	$1	$1	$0
PACKARD HUNTLEY	-	-	-	$5	$7	$28	$37	$44	$48	$44	$36	$36	$33	$35	$34
DUNWOODIE MOTTHAVEN	$52	$88	$22	$18	$40	-	-	-	-	-	-	-	-	-	-
RAINEY VERNON	$32	$60	$10	$31	$1	$1	$1	$1	$2	$2	$2	$3	$2	$3	$2
E179THST HELLGT ASTORIAE	$20	$40	$11	$16	$3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
EGRDNCTY 138 VALLYSTR 138 1	$3	$7	$8	$14	$20	$4	$3	$4	$3	$4	$4	$5	$4	$7	$6
MOTTHAVEN RAINEY	$30	$16	$5	-	-	-	$0	$0	$0	$0	$0	$0	$0	$0	$0
SHORE_RD 345 SHORE_RD 138 1	$2	-	$4	$36	$12	-	-	-	-	-	-	-	-	-	-
W49TH_ST 345 SPRNBRK 345 1	$7	$14	$1	$4	$21	-	-	-	-	-	-	-	-	-	-
HUNTLEY GARDENVILLE	-	-	-	$8	$6	$1	$4	$1	$2	$3	$5	$5	$8	$9	$10
DYSINGER EAST	$1	$15	$3	$8	$14	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
NIAGARA PACKARD	-	-	$3	$21	$18	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
STOLLE RD GARDENVILLE	-	-	-	-	-	$3	$4	$5	$5	$3	$6	$11	$7	$9	$9
GLENWD 138 SHORE_RD 138 1	-	$6	$8	$4	-	-	-	-	-	-	-	-	-	-	-
LEEDS HURLYAVE	$3	$2	-	$9	$2	-	-	-	-	-	-	-	-	-	-
EGRDNCTY 345 EGRDNCTY 138 1	$6	$0	$1	$4	$5	-	-	-	-	-	-	-	-	-	-

5.2. Ranking of Congested Elements

The identified congested elements from the ten-year projection of congestion are lined up with the past five years of identified historic congested elements to develop fifteen years of Demand$ Congestion statistics for each initially identified top constraint. The fifteen years of statistics are analyzed to determine recurring congestion or the mitigation of congestion from future system changes incorporated into the base CARIS system that may lead to exclusions. Ranking of the identified constraints is initially based on the highest present value of congestion over the fifteen-year period with five years historic and ten years projected.

Table 5-7 lists the ranked elements based on the highest present value of congestion over the fifteen years of the study, including both positive and negative congestion. Central East and Leeds - Pleasant Valley continue to be the paths with the greatest projected congestion. The top elements are evaluated in the next step for selection of the three studies.

Table 5-7: Ranked Elements Based on the Highest Present Value of Demand$ Congestion over the Fifteen Years Aggregate*

	Present Value of Demand$ Congestion ($M)		
	Historic	Projected	Total
CENTRAL EAST	$4,059	$4,955	$9,015
DUNWOODIE TO LONG ISLAND	$1,429	$428	$1,857
LEEDS PLEASANT VALLEY	$939	$399	$1,338
GREENWOOD	$543	$188	$730
NEW SCOTLAND LEEDS	$363	$10	$374
PACKARD HUNTLEY	$14	$294	$308
DUNWOODIE MOTTHAVEN	$285	$0	$285
RAINEY VERNON	$177	$14	$191
E179THST HELLGT ASTORIAE	$119	$0	$119
EGRDNCTY 138 VALLYSTR 138 1	$62	$33	$96

*The absolute value of congestion is reported.

The frequency of actual and projected congestion is shown in Table 5-8 below. The table presents the actual number of congested hours by constraint, from 2010 through 2014, and projected hours of congestion, from 2015 through 2024. The change in the number of projected hours of congestion, by constraint after each generic solution is applied, is shown in Appendix E.

Table 5-8: Number of Congested Hours by Constraint

# of DAM Congested Hours	Actual					CARIS Base Case Projected									
Constraint	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CENTRAL EAST	2,968	2,166	1,471	3,374	3,022	4,678	4,215	4,527	4,425	4,416	3,466	3,624	3,365	3,469	3,203
DUNWOODIE TO LONG ISLAND	4,513	6,219	4,777	6,031	5,583	7,869	7,667	7,778	7,502	7,517	7,840	7,920	7,908	8,056	8,108
LEEDS PLEASANT VALLEY	673	514	392	624	384	961	546	629	475	410	325	349	353	404	767
GREENWOOD	2,705	4,338	2,983	3,415	1,438	8,096	7,591	7,693	7,873	7,817	8,392	8,357	8,402	8,430	8,442
NEW SCOTLAND LEEDS	156	774	69	264	173	145	17	29	7	9	9	11	17	13	6
PACKARD HUNTLEY	-	-	-	-	308	3,604	4,729	4,816	5,019	4,809	4,449	4,326	4,209	4,291	4,112
DUNWOODIE MOTTHAVEN	765	828	644	504	190	0	0	0	1	0	0	0	0	0	0
RAINEY VERNON	3,131	3,785	2,166	2,166	641	410	4,953	5,308	5,409	5,388	5,142	5,381	4,930	5,223	5,070
E179THST HELLGT ASTORIAE	3,371	4,880	2,432	2,182	990	410	787	864	796	728	563	740	719	737	736
EGRDNCTY 138 VALLYSTR 138	1,880	2,812	2,934	5,908	5,142	2,183	5,491	5,962	5,727	6,086	5,009	5,491	5,574	5,791	5,780

5.3. Three CARIS Studies

5.3.1. Selection of the Three Studies[24]

Selection of the three CARIS studies is a two-step process in which the top ranked constraints are identified and utilized for further assessment in order to identify potential for grouping of constraints. Resultant grouping of elements for each of the top ranked constraints is utilized to determine the three studies.

In Step 1, the top five congested elements for the fifteen-year period (both historic (5 years) and projected (10 years)) are ranked in descending order based on the calculated present value of Demand$ Congestion for further assessment. In addition, per the selection procedure, congested elements whose projected Demand$ Congestion is observed to be materially higher than its historic Demand$ Congestion may also be included in Step 2. Based on this factor, the Western NY constraints were considered in the relaxation and grouping process.

In Step 2, the top congested elements from Step 1 are relieved independently by relaxing their limits. This is to determine if any of the congested elements need to be grouped with other elements, depending on whether new elements appear as limiting with significant congestion when a primary element is relieved. See Appendix E for a more detailed discussion. The assessed element groupings are then ranked based upon the highest change in production cost. For ease of presentation, the Eastern and Central NY constraints are presented in Figure 5-2 and the Western NY constraints in Figure 5-3.

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[24] Additional detail on the selection of the three studies is provided in Appendix E-2.

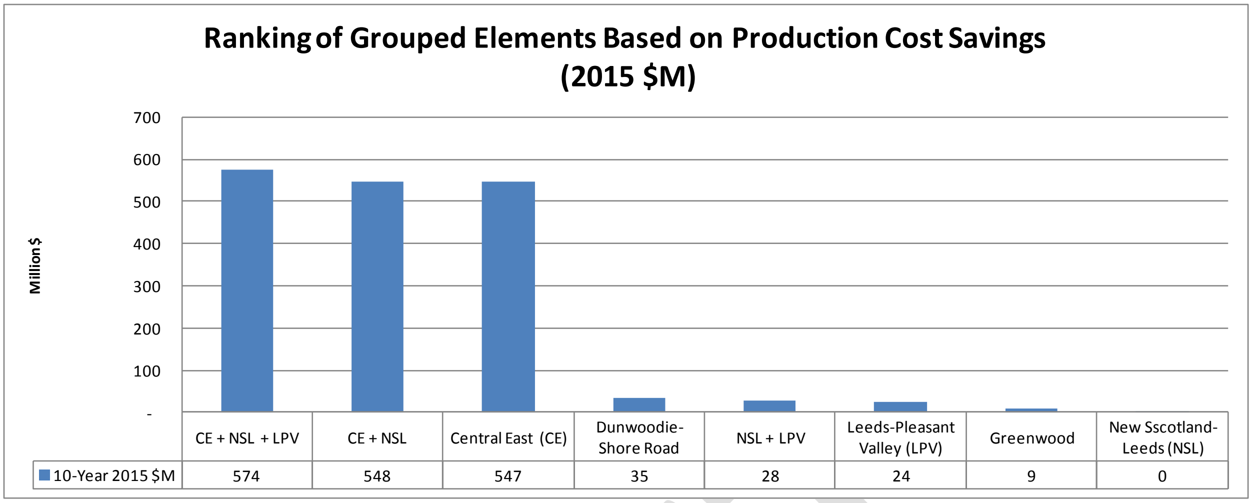

Figure 5-2: Production Costs Savings, 2015-2024 (2015$M)

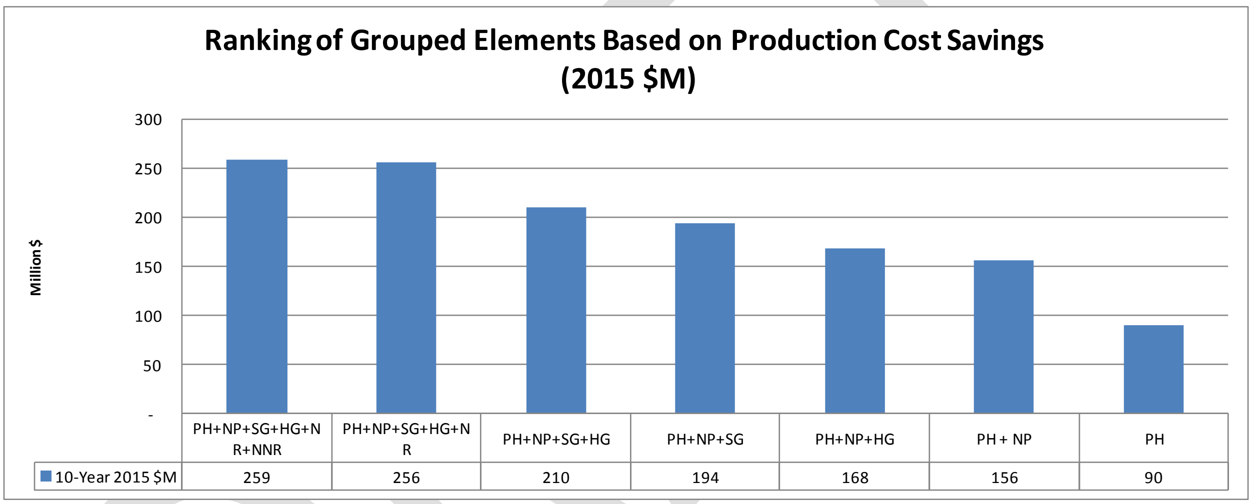

Figure 5-3: Production Costs Savings, 2015-2024 (2015$M)[25]

The three ranked groupings with the largest change in production cost are selected as the three CARIS studies: Central East-New Scotland-Pleasant Valley (CE-NS-PV), Central East (CE) and the Western NY 230 kV system (Huntley-Packard, Niagara Packard, Huntley-Gardenville, Stolle Road-Gardenville, and Niagara-Robinson Road). Tables 5-9 and 5-10 present the base case congestion associated with each of the three studies. Although the most significantly congested pathways continue to be in Central NY, increasing congestion is observed in Western NY through the forecast period. A detailed discussion on the ranking process is presented in Appendix E.

[25] The Western constraints in the relaxation process were: Huntley-Packard (HP), Niagara Packard (NP), Huntley-Gardenville (HG), Stolle Road-Gardenville (SG), Niagara-Robinson Road (NR), and Niagara-New Rochelle (NNR).

Table 5-9: Demand$ Congestion of the Top Three CARIS Studies (nominal $M)

Study	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Study 1: Central East-New Scotland-Pleasant Valley	738	644	744	700	817	598	615	598	652	709
Study 2: Central East	643	611	691	662	782	572	585	561	598	584
Study 3: Western 230kV System	32	45	50	55	51	47	52	48	53	54

Table 5-10: Demand$ Congestion of the Top Three CARIS Studies (2015$M)

Study	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Total
Study 1: Central East-New Scotland-Pleasant Valley	763	623	674	593	648	444	427	389	397	404	5,362
Study 2: Central East	665	591	626	561	620	425	406	365	364	333	4,955
Study 3: Western 230kV System	33	43	45	46	40	35	36	31	32	31	374

The location of the top three congested groupings, which define the three studies, along with their present value of congestion (in 2015 dollars) is presented in Figure 5-4.

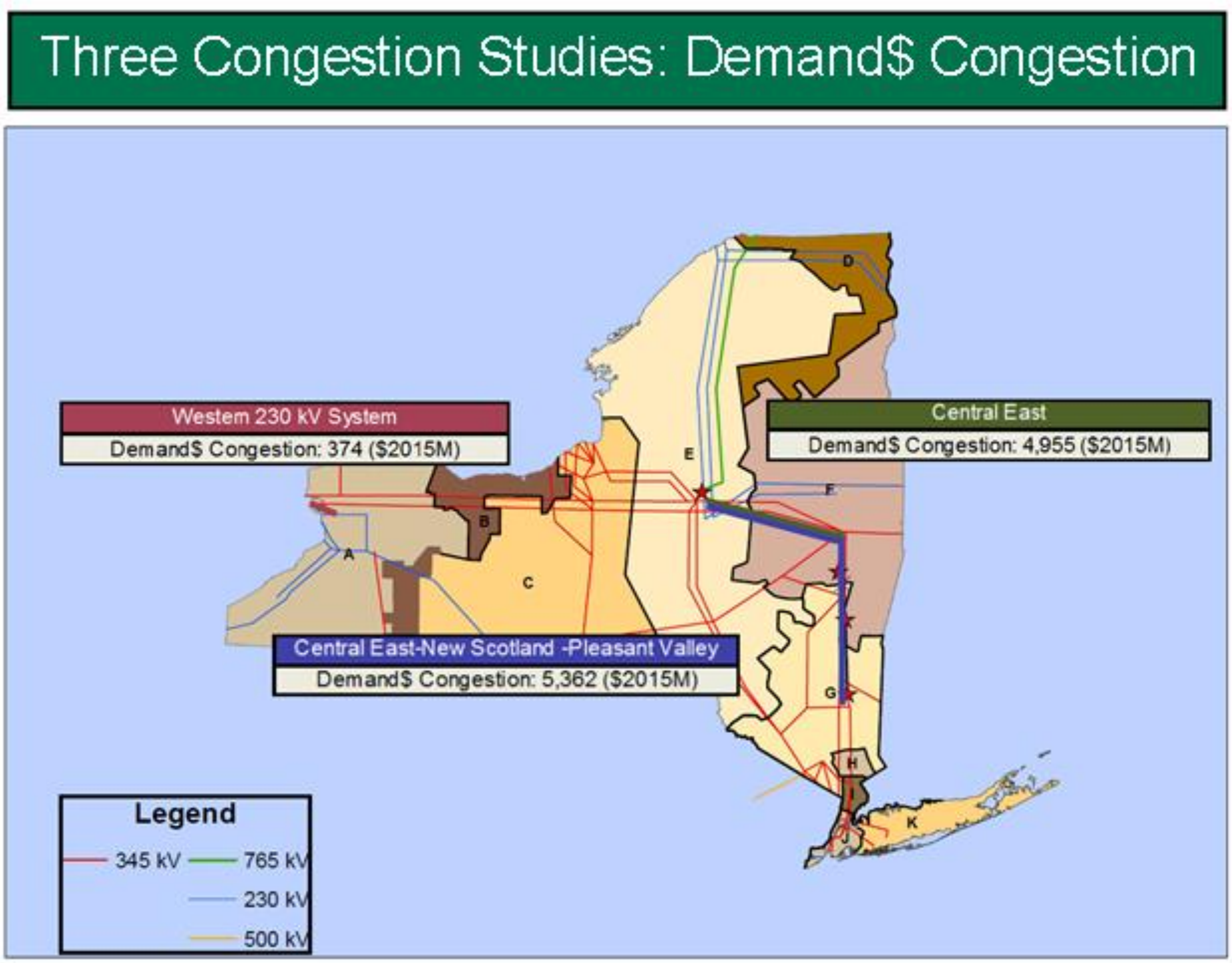

Figure 5-4: Base Case Congestion of Top 3 Congested Groupings, 2015-2024 (2015$M)

5.3.2. Generic Solutions to Congestion

The congestion of each of the three groupings being studied is mitigated by individually applying one of the generic resource types; transmission, generation, energy efficiency and demand response. The resource type is applied based on the rating and size of the blocks determined in the Generic Solutions Cost Matrix included in Appendix C and is consistent with the methodology explained in Section 4 of this report. Resource blocks were applied to relieve a majority of the congestion. Additional resource blocks were not added if diminishing returns would occur.

In regard to the generic solutions, it is important to note the following:

- Other solutions may exist which will alleviate the congestion on the studied elements.
- No attempt has been made to determine the optimum solution for alleviating the congestion.
- No engineering, physical feasibility study, routing study or siting study has been completed for the generic solutions. Therefore, it is unknown if the generic solutions can be physically constructed as studied.
- Generic solutions are not assessed for impacts on system reliability or feasibility.
- Actual projects will incur different costs.
- The generic solutions differ in the degree to which they relieve the identified congestion.
- For each of the base case and solution cases, HQ imports are held constant.

The discount rate of 6.843% used for the present values analysis is the weighted average of the after-tax Weighted Average Cost of Capital (WACC) for the NYTOs. The weighted average is based on the utilities' annual GWh energy consumption for 2014.

Tables 5-12, 5-15 and 5-18 present the impact of each of the solutions on Demand$ Congestion for each of the studies in 2015$. Transmission has the greatest impact on reducing Demand$ Congestion (45% to 91%) because adding a transmission solution addresses the underlying system constraint that was driving the congestion. The generation solution reduced Demand$ Congestion by 4% to 71%. A large portion of the production cost savings resulting from generation can be attributed to the efficiency advantage of the generic generation solution when compared to the system-wide heat rate. The demand response solution resulted in reducing Demand$ Congestion by 0 to 1%, as expected, since this solution impacted only the top 100 load hours. The energy efficiency solution reduced Demand$ Congestion by 7% to 20%.

Tables 5-13, 5-16 and 5-19 present the impact of each of the solutions on production costs for each of the studies in 2015$. Transmission had higher impacts than the generation solutions in all three studies. The impact of the Transmission solution on production costs ranges from $199M - $305M. The generation solution reduced production costs by $47M - $186M. The demand response solution resulted in the least production cost savings ($29M - $81M), again, as expected, since this solution impacted only the top 100 load hours. The energy efficiency solution shows the largest production cost savings (by $1.1B - $2.3B) because it directly reduces the energy production requirements.

The results of the three generic solutions are provided below with more detail in Appendix E. The following generic solutions were applied for each study:

Study 1: Central East – New Scotland – Pleasant Valley

The following generic solutions were applied for Central East – New Scotland - Pleasant Valley Study:

- Transmission: A new 345 kV line from Edic to New Scotland to Pleasant Valley, 150 Miles. The new line increases the Central East voltage transfer limit by about 700 MW and the UPNY-SENY thermal capability by approximately 1200 MW. Cost estimates are: $480M (low); $675M (mid); and $900M (high).
- Generation: A new 1,320 MW Plant at Pleasant Valley. Cost estimates are: $1,464M (low); $1,951M (mid); and $2,439M (high).
- Demand Response: 200 MW Demand Response in Zone F; 200 MW in Zone G; 800 MW in Zone J. Cost estimates are $588M (low); $744M (mid); and $924M (high).
- Energy Efficiency: 200 MW Energy Efficiency in Zone F; 200 MW in Zone G; 800 MW in Zone J. Cost estimates are $2,088M (low); $2,304M (mid); and $2,520M (high).

Table 5-11 shows the Demand$ Congestion of Central East – New Scotland – Pleasant Valley for 2019 and 2024 before and after each of the generic solutions is applied. The Base Case congestion numbers, $817M for 2019 and $709M for 2024, are taken directly from Table 5-5 representing the level of congestion of the Study 1 before the solutions.

Table 5-11: Demand$ Congestion Comparison for Central East – New Scotland – Pleasant Valley Study (nominal $M)

CE-NS-PV	2019			2024		
Resource Type	Base Case	Solution	%Change	Base Case	Solution	%Change
Transmission	817	422	(48%)	709	356	(50%)
Generation-1320MW	817	783	(4%)	709	600	(15%)
Demand Response-1200MW	817	811	(1%)	709	677	(5%)
Energy Efficiency-1200MW	817	709	(13%)	709	596	(16%)

Table 5-12 shows the Demand$ Congestion reduction for the 10-year Study Period in 2015 dollars from 2015 to 2024 for the Central East – New Scotland – Pleasant Valley study after generic solutions were applied.

Table 5-12: Demand$ Congestion Comparison for Central East – New Scotland – Pleasant Valley Study (2015$M)

Resource Type	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Total	%Change
Transmission	(331)	(293)	(317)	(288)	(313)	(203)	(182)	(172)	(179)	(201)	(2,479)	(46%)
Generation-1320MW	(78)	(36)	(18)	(13)	(27)	(6)	(13)	(14)	(24)	(62)	(291)	(5%)
Demand Response-1200MW	(15)	(7)	(12)	(5)	(5)	(2)	(4)	(4)	(9)	(18)	(79)	(1%)
Energy Efficiency-1200MW	(95)	(81)	(83)	(66)	(86)	(61)	(55)	(50)	(61)	(64)	(703)	(13%)

Table 5-13 shows the production cost savings expressed as the present value in 2015 dollars from 2015 to 2024 for the Central East – New Scotland – Pleasant Valley study after generic solutions were applied.

Table 5-13: Central East – New Scotland – Pleasant Valley Study: NYCA-wide Production Cost Savings (2015$M)

Resource Type	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Total
Transmission	(31)	(25)	(30)	(29)	(37)	(31)	(29)	(33)	(31)	(30)	(305)
Generation-1320MW	(17)	(15)	(6)	(8)	(7)	(18)	(20)	(9)	(11)	(23)	(133)
Demand Response-1200MW	(9)	(8)	(8)	(7)	(8)	(8)	(8)	(8)	(8)	(8)	(81)
Energy Efficiency-1200MW	(246)	(238)	(225)	(218)	(223)	(237)	(235)	(230)	(221)	(215)	(2,287)

Note: Totals may differ from sum of annual values due to rounding.

The Edic – New Scotland – Pleasant Valley 345 kV transmission solution is projected to relieve the congestion across existing Central East – New Scotland – Pleasant Valley transmission lines by 48% in 2019 and 50% in 2024 respectively, as shown in Table 5-11. As presented in Table 5-13, total ten year NYCA-wide production cost savings is $305 million (2015$) as the result of better utilization of economic generation in the state and economic imports from neighboring regions made available by the large scale transmission upgrades represented by this generic transmission solution.

The generation solution is projected to reduce congestion by 4% in 2019 and 15% in 2024. The ten-year production cost savings of $133 million (2015$) are due to the uncongested location and the assumed heat rate of the generic generating unit compared to the average system heat rate. Efficient generator solutions reduce imports from neighbors and enable a more efficient and lower cost NYCA generation market. Savings accrue in lower production cost as well as reduced congestion.

The Zones G and J Demand Response solution is projected to reduce congestion by 1% in 2019 and 5% in 2024, while the ten-year total production cost saving is $81 million (2015$). DR solutions show lower reduction in production cost than the generation, transmission and energy efficiency solutions due to the limited hours impacted by the solution.

The Zones G and J Energy Efficiency solution is projected to reduce congestion by 13% in 2019 and 16% in 2024, while the ten-year total production cost saving is $2,287 million (2015$). The relatively large value of production cost saving is largely attributable to the reduction in energy use of the EE solution itself. For this reason EE solutions show significantly greater reductions in production cost than the generation, transmission or demand response solutions.

Study 2: Central East

The following generic solutions were applied for Central East study:

- Transmission: A new 345 kV line from Edic to New Scotland, 85 Miles. The new line increases the Central East voltage limit by approximately 580 MW. Cost estimates are: $272M (low); $383M (mid); and $510M (high).
- Generation: A new 660 MW Plant at New Scotland. Cost estimates are: $661M (low); $881M (mid); and $1,102M (high).
- Demand Response: 200 MW Demand Response in Zone F; 200 MW in Zone G; 200 MW in Zone J. Cost estimates are $294M (low); $372M (mid); and $462M (high).
- Energy Efficiency: 200 MW Energy Efficiency in Zone F; 200 MW in Zone G; 200 MW in Zone J. Cost estimates are $1,044M (low); $1,152M (mid); and $1,260M (high).

Table 5-14 shows the Demand$ Congestion of Central East for 2019 and 2024 before and after each of the generic solutions is applied.

Table 5-14: Demand$ Congestion Comparison for Central East Study (nominal $M)

CE	2019			2024		
Resource Type	Base Case	Solution	%Change	Base Case	Solution	%Change
Transmission	782	412	(47%)	584	327	(44%)
Generation-660MW	782	751	(4%)	584	540	(8%)
Demand Response-600MW	782	780	(0%)	584	585	0%
Energy Efficiency-600MW	782	711	(9%)	584	537	(8%)

Table 5-15 shows the Demand$ Congestion reduction for the 10-year Study Period in 2015 dollars from 2015 to 2024 for the Central East study after generic solutions were applied.

Table 5-15: Demand$ Congestion Comparison for Central East Study (2015$M)

Resource Type	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Total	%Change
Transmission	(269)	(276)	(282)	(264)	(294)	(200)	(181)	(173)	(159)	(146)	(2,245)	(45%)
Generation-660MW	(54)	(4)	(13)	(1)	(24)	(34)	(15)	(20)	(18)	(25)	(208)	(4%)
Demand Response-600MW	0	0	(2)	0	(1)	0	0	0	(1)	0	(3)	(0%)
Energy Efficiency-600MW	(41)	(40)	(34)	(34)	(56)	(29)	(31)	(24)	(33)	(27)	(348)	(7%)

Table 5-16 shows the NYCA-wide production cost savings expressed as the present value in 2015 dollars from 2015 to 2024 for the Central East study after generic solutions were applied.

Table 5-16: Central East Study: NYCA-wide Production Cost Savings (2015$M)

Resource Type	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Total
Transmission	(23)	(22)	(23)	(25)	(34)	(29)	(25)	(31)	(26)	(25)	(262)
Generation-660MW	(1)	(3)	2	(6)	(5)	(8)	(14)	(4)	(1)	(6)	(47)
Demand Response-600MW	(4)	(4)	(5)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(40)
Energy Efficiency-600MW	(126)	(121)	(114)	(108)	(112)	(121)	(119)	(117)	(113)	(111)	(1,162)

Note: Totals may differ from sum of annual values due to rounding.

The addition of the Edic-New Scotland line is projected to relieve the Central East congestion by 47% in 2019 and 44% in 2024. The total ten-year production cost savings of $262 million (2015$) are again due to increased use of lower cost generation in upstate and increased levels of imports compared to the base case.

The generation solution is projected to reduce congestion by 4% in 2019 and 8% in 2024. The ten-year production cost savings of $47 million (2015$) are derived from the heat rate efficiency advantage of the new generic unit compared to the average system heat rate. Imports are significantly reduced in this solution. Efficient generator solutions reduce imports from neighbors and enable a more efficient and lower cost NYCA generation market. Savings accrue in lower production cost as well as reduced congestion.

The Zones F, G and J Demand Response solution is projected to have negligible impact on congestion in 2019 and in 2024, while the ten-year total production cost saving is $40 million (2015$). DR solutions show lower reduction in production cost than the generation, transmission and energy efficiency solutions due to the limited hours impacted by the solution.

The Zones F, G, and J Energy Efficiency solution is projected to reduce congestion by 9% in 2019 and 8% in 2024, while the ten-year total production cost saving is $1,162 million (2015$). The relative large value of production cost saving is largely attributable to the reduction in energy use of the EE solution itself. EE solutions show greater reductions in production cost than the generation, transmission and energy efficiency solutions.

Study 3: Western NY 230 kV System

The following generic solutions were applied for the Western NY study:

- Transmission: A new 230 kV line from Niagara to Gardenville; 35 Miles. The new line increases the Dysinger East normal transfer limit by approximately 630 MW. Cost estimates are: $80M (low); $113M (mid); and $150M (high).
- Generation: Install a new 660 MW Plant at Gardenville. Cost estimates are: $661M (low); $881M (mid); and $1,102M (high).
- Demand Response: 200 MW in Zone A; 200 MW in Zone B; 200 in Zone C. Cost estimates are: $661M (low); $881M (mid); and $1,102M (high).
- Energy Efficiency: 200 MW in Zone A; 200 MW in Zone B; 200 in Zone C. Cost estimates are $1,044M (low); $1,152M (mid); and $1,260M (high).

Table 5-17 shows the Demand$ Congestion of Western NY for 2019 and 2024 before and after each of the generic solutions is applied. Transmission has the greatest impact in reducing congestion on the Western NY 230 kV system.

Table 5-17: Demand$ Congestion Comparison for Western NY (nominal $M)

WEST	2019			2024		
Resource Type	Base Case	Solution	%Change	Base Case	Solution	%Change
Transmission	51	6	(88%)	54	2	(96%)
Generation-660MW	51	19	(63%)	54	12	(78%)
Demand Response-600MW	51	51	(0%)	54	53	(2%)
Energy Efficiency-600MW	51	42	(18%)	54	43	(20%)

Table 5-18 shows the Demand$ Congestion reduction for the 10-year Study Period in 2015 dollars from 2015 to 2024 for the Western NY study after generic solutions were applied

Table 5-18: Demand$ Congestion Comparison for Western NY (2015$M)

Resource Type	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Total	%Change
Transmission	(28)	(38)	(39)	(40)	(36)	(33)	(35)	(29)	(31)	(29)	(339)	(91%)
Generation-660MW	(25)	(30)	(28)	(30)	(26)	(25)	(29)	(23)	(25)	(24)	(265)	(71%)
Demand Response-600MW	1	0	0	(0)	(0)	(1)	(0)	(0)	(0)	(0)	(1)	(0%)
Energy Efficiency-600MW	(5)	(9)	(9)	(8)	(7)	(8)	(9)	(8)	(7)	(6)	(75)	(20%)

Table 5-19 shows the NYCA-wide production cost savings expressed as the present value in 2015 dollars from 2015 to 2024 for the Western NY study after the generic solutions were applied.

Table 5-19: Western NY: NYCA-wide Production Cost Savings (2015$M)

Resource Type	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Total
Transmission	(14)	(15)	(22)	(19)	(19)	(26)	(21)	(25)	(19)	(19)	(199)
Generation-660MW	(13)	(16)	(13)	(15)	(11)	(24)	(31)	(22)	(17)	(23)	(186)
Demand Response-600MW	(3)	(3)	(2)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(29)
Energy Efficiency-600MW	(110)	(109)	(102)	(96)	(101)	(112)	(109)	(108)	(103)	(105)	(1,054)

Note: Totals may differ from sum of annual values due to rounding.

The addition of the Niagara to Gardenville 230 kV transmission line is projected to relieve Western 230 kV congestion by 88% in 2019 and 96% in 2024, and results in a projected total ten-year production cost savings of $199 million (2015$). Reduction in the Western 230 kV congestion reduces dependence on higher-cost generation in the West zone and allows NYCA load better access to economic imports from neighbors.

The generation solution is projected to reduce congestion across NYCA for the planning horizon. The ten-year production cost savings of $186 million (2015$) are due to the uncongested location and the assumed better heat rate of the generic generating unit compared to the average system heat rate. Efficient generator solutions reduce imports from neighbors and enable a more efficient and lower cost NYCA generation market. Savings accrue in lower production cost as well as reduced congestion.

The Zones A, B and C Demand Response solution is projected to reduce congestion by 1% in 2019 and 2% in 2024, while the ten-year total production cost saving is $29 million (2015$). DR solutions show lower reduction in production cost than the generation, transmission and energy efficiency solutions due to the limited hours impacted by the solution.

The Zones A, B, and C Energy Efficiency solution is projected to reduce congestion by 13% in 2019 and 11% in 2024, while the ten-year total production cost saving is $1,054 million (2015$). The relative large value of production cost saving is largely attributable to the reduction in energy use of the EE solution itself. EE solutions show greater reductions in production cost than the generation and transmission solutions.

The NYCA-wide production cost savings of the three generic solutions for the three studies are summarized and shown in Figure 5-5.

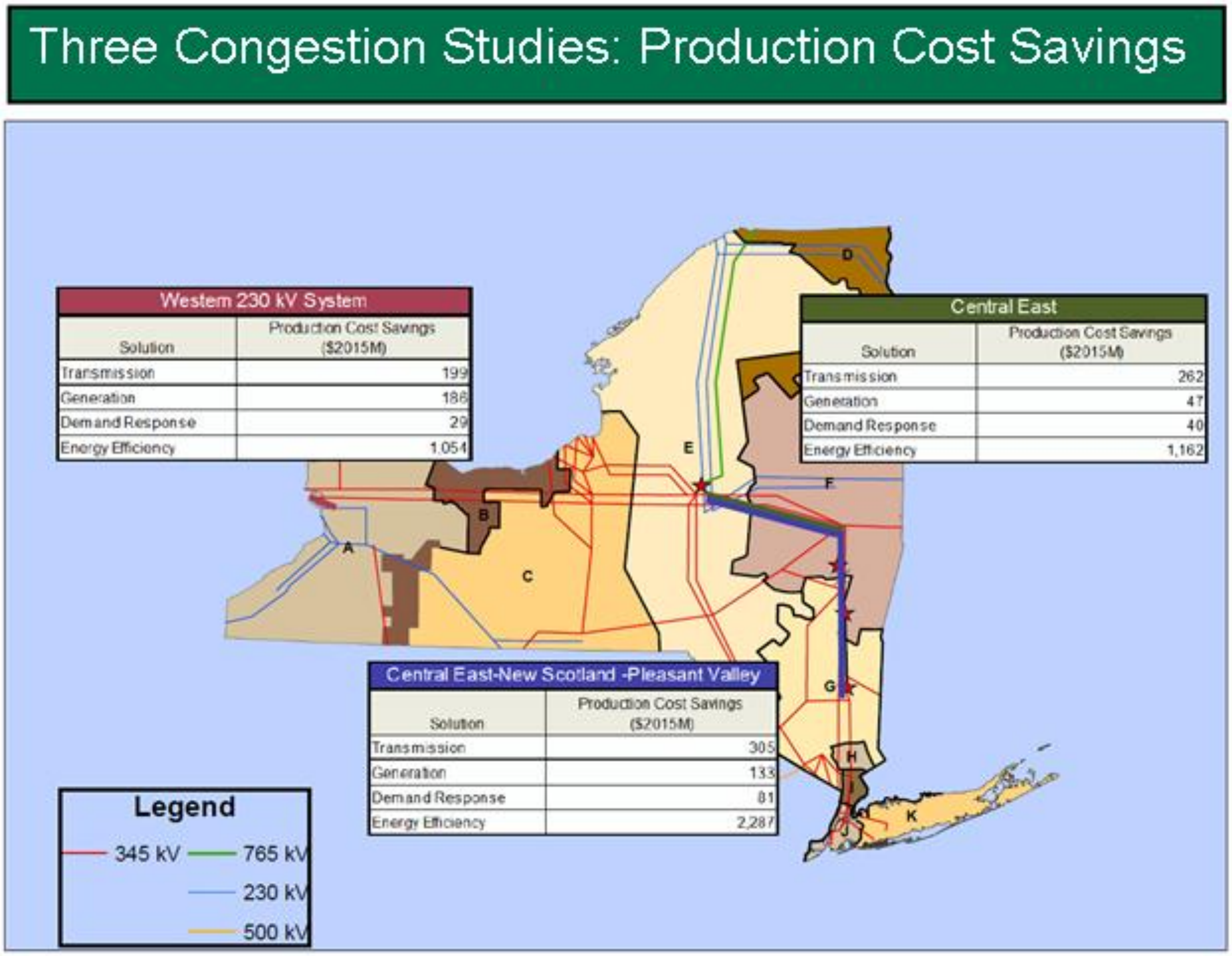

Figure 5-5: Total NYCA-wide Production Cost Savings 2015-2024 (2015$M)

5.4. Benefit/Cost Analysis

The NYISO conducted the benefit/cost analysis for each of the three: Central East – New Scotland – Pleasant Valley, Central East, and Western NY. The CARIS benefit/cost analysis assumes a levelized generic carrying charge rate of 16.26% for transmission and generation solutions. Therefore, for a given generic solution pertaining to a constrained element, the carrying charge rate, in conjunction with an appropriate discount rate (see description in Section 5.3.2 above) yields a capital recovery factor, which, in turn, is used to calculate the benefit/cost ratio.

$$\text{Benefit/Cost ratio} = \frac{\text{Present Value of Production Cost Savings}}{\text{Overnight Costs x Capital Recovery Factor}}$$

The 16.26% carrying charge rate used in these CARIS benefit/cost calculations reflects generic figures for a return on investment, federal and state income taxes, property taxes, insurance, fixed O&M, and depreciation (assuming a straight-line 30-

year method). The calculation of the appropriate capital recovery factor, and, hence, the B/C ratio, is based on the first ten years of the 30-year period,[26] using a discount rate of 6.843%, and the 16.26% carrying charge rate, yielding a capital recovery factor equal to 1.27.

Unlike the 2013 CARIS, the energy efficiency and demand response solutions *do* include estimates of both program subsidies as well as customer implementation costs. However, as in the 2013 study, for the demand response solution, the overnight costs do not reflect energy payments to demand-response providers participating in NYISO EDRP and SCR programs associated with the peak load reductions. While there were no events in the summer of 2014, during the six-hour event on January 7, 2014, SCRs received an average of $463.15/MWh in energy payments; and EDRP resources received $545.65/MWh, or in the range of $3,000 per MW for SCR/EDRP resources responding for the entire six hours. Similarly, projected capacity payments for these resources are not incorporated as costs.

5.4.1. Cost Analysis

Table 5-20 includes the total cost estimate for each generic solution based on the unit pricing and the detailed cost breakdown for each solution included in Appendix E. These are simplified estimates of overnight installation costs and do not include any of the many complicating factors that could be faced by individual projects. On-going fixed operation and maintenance costs and other fixed costs of operating the facility are captured in the capital recovery factor.

[26] The carrying charge rate of 16.26% was based on a 30-year period because the Tariff provisions governing Phase 2 of CARIS refer to calculating costs over 30 years for information purposes. See OATT Attachment Y, Section 31.5.3.3.4.

Table 5-20: Generic Solution Overnight Costs for Each Study[27]

Generic Solution Cost Summary ($M)			
Studies	Study 1: Central East-New Scotland-Pleasant Valley	Study 2: Central East	Study 3: Niagara-Gardenville
TRANSMISSION			
Substation Terminals	Edic to New Scotland to Pleasant Valley	Edic to New Scotland	Niagara to Gardenville
Miles	150	85	35
Voltage	345 kV	345 kV	230 kV
High	900	510	150
Mid	675	383	113
Low	480	272	80
GENERATION			
Substation Terminal	Pleasant Valley	New Scotland	Gardenville
# of 330 MW Blocks	4	2	2
High	2,439	1,102	1,102
Mid	1,951	881	881
Low	1,464	661	661
DR			
Zone	F , G and J	F ,G and J	A, B, and C
# of 200 MW Blocks	6	3	3
High	924	462	462
Mid	744	372	372
Low	588	294	294
EE			
Zone	F , G and J	F , G and J	A, B, and C
# of 200 MW Blocks	6	3	3
High	2,520	1,260	1,260
Mid	2,304	1,152	1,152
Low	2,088	1,044	1,044

5.4.2. Primary Metric Results

The primary benefit metric for the three CARIS studies is the reduction in NYCA-wide production costs. Table 5-21 shows the production cost savings used to calculate the benefit/cost ratios for the generic solutions. In each of the three studies the Energy Efficiency solution produced the highest production cost savings because it directly reduces the energy production requirements. Similarly, in each study the transmission solutions produced higher production cost savings than generation. In all cases, the Demand Response solution had the least impact on production cost savings.

[27] Appendix E contains a more detailed description of the derivation of the generic solution costs.

Table 5-21: Production Cost Generic Solutions Savings 2015-2024 (2015$M)

	Ten-Year Production Cost Savings ($2015M)			
	Transmission Solution	Generation Solution	Demand Response Solution	Energy Efficiency Solution
Study 1: Central East-New Scotland-Pleasant Valley	305	133	81	2,287
Study 2: Central East	262	47	40	1,162
Study 3: Western 230kV System	199	186	29	1,054

5.4.3. Benefit/Cost Ratios

Figure 5-6 shows the benefit/cost ratios for each study and each generic solution.

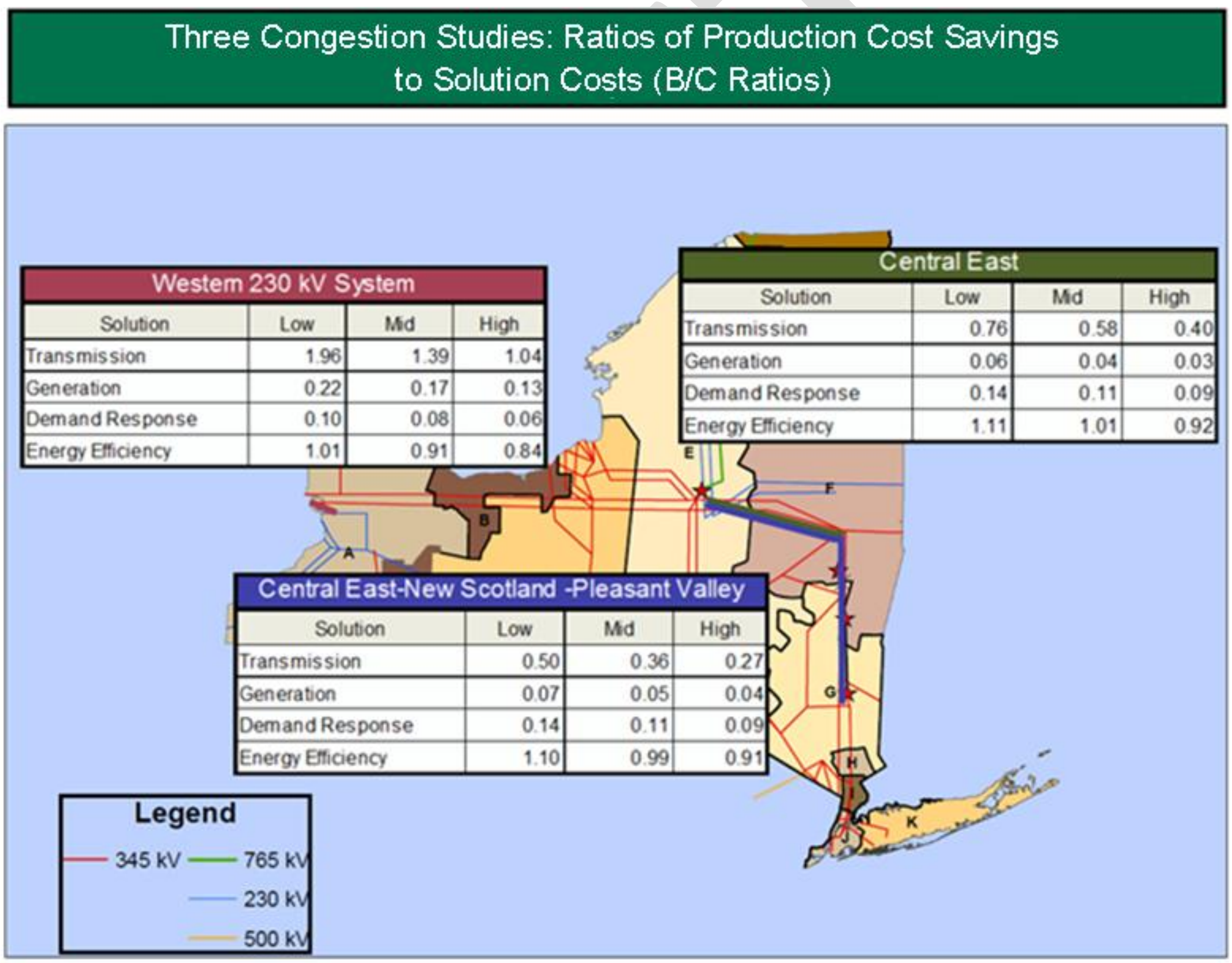

Figure 5-6: B/C Ratios (High, Mid, and Low Cost Estimate Ranges)

5.4.4. Additional Metrics Results

Additional metrics, which are provided for information purposes in Phase 1, are presented in Table 5-22, Table 5-23, Table 5-24 and Table 5-25 to show the ten-year total change in: (a) generator payments; (b) LBMP load payments; (c) TCC payments (congestion rents); (d) losses; (e) emission costs/tons; and (f) ICAP MW and cost impact, after the generic solutions are applied. The values represent the generic solution case values less the base case values for all the metrics except for the ICAP metric. Details on the calculations are in Appendix E.

While all but the ICAP metric are from the production cost simulation program, the ICAP metric is computed using the latest available information from the installed reserve margin (IRM), locational capacity requirement (LCR), and ICAP Demand Curves.[28] For Variant 1, the ISO measured the cost impact of a solution by multiplying the forecast cost per megawatt-year of Installed Capacity (without the solution in place) by the sum of the megawatt impact. For Variant 2, the cost impact of a solution is calculated by forecasting the difference in cost per megawatt-year of Installed Capacity with and without the solution in place and multiplying that difference by fifty percent (50%) of the assumed amount of NYCA Installed Capacity available. Details on the ICAP metric calculations and 10 years of results are provided in Appendix E.

28 http://www.nyiso.com/public/webdocs/markets_operations/market_data/icap/Announcements/Info_and_Announcements/Summer_2013_Documents/Demand_Curve_Summer_2013_FINAL.pdf.

Table 5-22: Ten-Year Change in Load Payments, Generator Payments, TCC Payments and Losses Costs (2015$M)[29]

	LOAD PAYMENT	NYCA LOAD PAYMENT	EXPORT PAYMENT	GENERATOR PAYMENT	NYCA GENERATOR PAYMENT	IMPORT PAYMENT	TCC PAYMENT	LOSSES COSTS
TRANSMISSION SOLUTIONS								
Edic-New Scotland-Pleasant Valley	$171	$72	$99	$402	$420	($18)	($780)	$0
Edic-New Scotland	$133	$42	$91	$285	$319	($34)	($635)	($35)
Niagara-Gardenville	($162)	($177)	$15	$21	$0	$21	($238)	$30
GENERATION SOLUTIONS								
Pleasant Valley	($198)	($472)	$274	($57)	$116	($173)	($111)	($7)
New Scotland	($57)	($231)	$174	($84)	($10)	($74)	$54	$48
Gardenville	($655)	($844)	$189	($564)	($357)	($207)	$37	$2
DEMAND RESPONSE SOLUTIONS								
F (200), G(200), J(800)	($124)	($142)	$18	($55)	($37)	($18)	($67)	($3)
F (200), G(200), J(200)	($42)	($54)	$12	($16)	($7)	($9)	($25)	($1)
A (200), B(200), C(200)	($43)	($51)	$8	($47)	($38)	($9)	$14	$1
ENERGY EFFICIENCY SOLUTIONS								
F (200), G(200), J(800)	($3,024)	($3,400)	$376	($2,572)	($2,235)	($337)	($328)	($75)
F (200), G(200), J(200)	($1,466)	($1,673)	$207	($1,270)	($1,089)	($181)	($149)	($18)
A (200), B(200), C(200)	($1,851)	($1,954)	$103	($1,763)	($1,546)	($217)	$172	$125

Note: A negative number implies a reduction in payments

Table 5-23: ICAP MW Impact

Study	Solution	Y2024 MW Impact (MW)			
		J	G-J	K	NYCA
Study 1: Central East - New Scotland - Pleasant Valley	Transmission	159	233	93	629
	Generation	348	556	204	1,426
	Energy Efficiency	379	556	222	1,502
	Demand Response	349	513	205	1,386
Study 2: Central East	Transmission	(34)	(50)	(20)	(136)
	Generation	73	107	43	293
	Energy Efficiency	188	276	110	745
	Demand Response	166	243	97	657
Study 3: Western 230kV System	Transmission	-	-	-	-
	Generation	58	85	34	233
	Energy Efficiency	47	69	28	187
	Demand Response	56	82	33	221

Table 5-24: ICAP $Impact

[29] Load Payments and Generator Payments are Tariff-defined additional metrics. The NYCA Load Payment and Export Payment values provide a breakdown of Load Payments by internal and external loads; NYCA Generator Payment and Import Payment provide a breakdown of Generator Payments by internal and external generators.

		ICAP Saving (2015 M$)	
Study	Solution	V1	V2
Study 1: Central East - New Scotland - Pleasant Valley	Transmission	377	2,797
	Generation	859	6,255
	Energy Efficiency	901	6,623
	Demand Response	832	6,117
Study 2: Central East	Transmission	(82)	(608)
	Generation	174	1,295
	Energy Efficiency	447	3,310
	Demand Response	394	2,923
Study 3: Western 230kV System	Transmission	-	-
	Generation	139	1,031
	Energy Efficiency	112	836
	Demand Response	132	985

The ten-year changes in total emissions resulting from the application of generic solutions are reported in Table 5-25 below. The base case ten-year emission totals for NYCA are: CO_2 = 316,157 thousand- tons, SO_2= 122,070 tons and NO_x = 207,126 tons. The study results reveal that all of the generic solutions impact emissions by less than 10% for CO_2 emissions. Energy efficiency had the most significant impact with reductions in the 3%-5% range. Transmission and generation solutions in the Central NY actually increased the CO_2 emissions in the range of 0.47% - 0.78% due to the higher utilization of coal units in western New York. This effect was not observed with the Western 230 kV solution which resulted in a reduction of 0.22% (for generation) and 1.44% (for transmission). Demand response had reductions of less than 0.2% in CO_2 emissions.

SO_2 emission impacts ranged from an increase of 7.7% for the Central East – New Scotland- Pleasant Valley (CE-NS-PV) transmission solution to a reduction of 13.9% for the West generation solution, as the specific solution impacted the capacity factor of Western NY coal. Similarly, the NOx emission impacts ranged from an increase of 1.7% for the CE-NS-PV transmission solution to a reduction of 3.7% for the West generation solution.

The current Installed Capacity in NYCA as reported in the 2015 Gold Book is 39,039 MW. The generic generation solutions of 1,320 and 660 MWs represent the equivalent of a 3.4% and 1.7% increase, respectively, in Installed Capacity. The generic demand response solutions of 1,200 MW and 600 MW of DR and EE could be considered as additional resources which would be equivalent to 3.2% and 1.6%, respectively, of Installed Capacity. The capability of the generic transmission solutions is 1,986 MVA (345 kV) and 566 MVA (230 kV), which would increase transfer limits across the system from 600 to 1200 MW, on the order of 1.5% - 3% of Installed Capacity. The three generic solutions can be considered to change the fleet emission characteristics on the order of 1.5% – 3.5%. The comparison of the relative emission changes among solution types and across locations provides insight about the relative air related impacts if the emissions assumptions come to fruition. The emissions results include only emissions from NYCA units. The external emissions impacts associated with changes in NYCA imports are not reported.

Table 5-25: Ten-Year Change in NYCA CO_2, SO_2 and NOx Emissions (2015$M)

Study	Generic Solutions	SO2		CO2		NOX	
		Tons	Cost($M)	1000Tons	Cost($M)	Tons	Cost($M)
	Transmission						
Study 1: CE-NS-PV	Edic-New Scotland-Pleasant Valley	9,423	$0.8	2,026	$21.0	3,431	$0.3
Study 2: CE	Edic-New Scotland	7,549	$0.6	1,877	$18.6	3,338	$0.3
Study 3: WEST	Niagara-Gardenville	(8,878)	($0.5)	(4,562)	($46.2)	(1,327)	($0.1)
	Generation						
Study 1: CE-NS-PV	Pleasant Valley	(2,075)	($0.1)	2,465	$27.4	(4,707)	($0.5)
Study 2: CE	New Scotland	(1,601)	($0.0)	1,487	$14.2	(2,145)	($0.2)
Study 3: WEST	Gardenville	(16,942)	($1.1)	(692)	($6.4)	(7,642)	($0.6)
	Demand Response						
Study 1: CE-NS-PV	F (200), G(200), J(800)	(283)	($0.0)	(598)	($5.7)	(799)	($0.1)
Study 2: CE	F (200), G(200), J(200)	(95)	($0.0)	(237)	($2.3)	(321)	($0.0)
Study 3: WEST	A (200), B(200), C(200)	(234)	($0.0)	(207)	($1.8)	(186)	$0.0
	Energy Efficiency						
Study 1: CE-NS-PV	F (200), G(200), J(800)	(2,253)	($0.1)	(16,914)	($149.2)	(6,623)	($0.6)
Study 2: CE	F (200), G(200), J(200)	(342)	$0.0	(8,066)	($72.0)	(2,643)	($0.2)
Study 3: WEST	A (200), B(200), C(200)	(11,193)	($0.9)	(11,520)	($104.5)	(6,826)	($0.7)

5.5. Scenario Analysis

Scenario analysis is performed to explore the impact on congestion associated with variables to the base case. Since this is an economic study and not a reliability analysis, these scenarios focus upon factors that impact the magnitude of congestion across constrained elements.

A forecast of congestion is impacted by many variables for which the future values are uncertain. Scenario analyses are methods of identifying the relative impact of pertinent variables on the magnitude of congestion costs. The CARIS scenarios were presented to ESPWG and modified based upon the input received and the availability of NYISO resources. The focus of these analyses was to examine the impact of greater penetration levels of solar installations, fuel price and load forecast uncertainties, costs of emissions, and removing the Athens SPS from service. The objective of the scenario analysis is to determine the change in the costs of congestion that is caused by variables that differ from their base case values. The simulations were conducted for the entire 10-year Study Period.

Table 5-26 summarizes the scenarios studied in CARIS Phase 1. The scenarios consider the effects of changes to the base case model. These changes are described as “Variables” in the table below.

Table 5-26: Scenario Matrix

Scenario	Description
Higher Load Forecast	Higher Growth Rate (net increase of 400 GWh from base forecast)
Lower Load Forecast	Lower Growth Rate (net decrease of 170 GWh from base forecast)
Athens SPS Out of Service	2015-2024 (June)
Higher Solar Penetration	3,800 MWs of Solar-PV (distributed state-wide) by 2024; 1.5*base forecast penetration
Higher Natural Gas Prices	Derived from 2015 EIA AEO High Forecast
Lower Natural Gas Prices	Derived from 2015 EIA AEO Low Forecast
Higher CO_2 Emissions Cost	Increased growth rate for CO_2 Allowance Costs (high range of forecasted values)
Double Natural Gas Prices Differential	Midstate & New England / Upstate differential doubled
Half Natural Gas Prices Differential	Midstate & New England / Upstate differential halved

Table 5-27 presents the impact of ten scenarios selected for study. Those impacts are expressed as the change in congestion costs between the base case and the scenario case.

Table 5-27: Comparison of Base Case and Scenario Cases, 2019 and 2024 (Nominal $M)

Demand Congestion Change ($M)	2019 Scenarios:(Change in Demand$ Congestion from Base Case)(Nominal $M)								
	Higher Load Forecast	Lower Load Forecast	Athens SPS Out of Service	High Solar Penetration	Higher Natural Gas Prices	Lower Natural Gas Prices	Higher CO2 Emissions Cost	Double Natural Gas Prices Differential	Half Natural Gas Prices Differential
CENTRAL EAST	(2)	(21)	(1)	(14)	63	(169)	12	533	(401)
DUNWOODIE TO LONG ISLAND	1	(0)	(1)	(0)	2	(6)	1	0	3
LEEDS PLEASANT VALLEY	4	(3)	16	(0)	(0)	(10)	0	(12)	7
GREENWOOD	5	(7)	(0)	(1)	2	(4)	(1)	(8)	9
NEW SCOTLAND LEEDS	0	0	2	0	(0)	0	(0)	0	0
PACKARD HUNTLEY	1	(0)	(0)	(0)	(1)	0	6	2	(0)
DUNWOODIE MOTTHAVEN	0	0	0	0	0	0	0	0	0
RAINEY VERNON	0	(0)	(0)	(0)	0	(0)	0	(1)	2
E179THST HELLGT ASTORIAE	0	0	0	0	0	0	0	0	0
EGRDNCTY 138 VALLYSTR 138 1	0	(0)	0	(0)	0	(1)	1	(2)	1
Central East – New Scotland Pleasant Valley	2	(24)	17	(14)	63	(178)	12	522	(394)
Central East	(2)	(21)	(1)	(14)	63	(169)	12	533	(401)
Western 230 kV System	1	(0)	0	(0)	0	2	5	2	(1)

Demand Congestion Change ($M)	2024 Scenarios:(Change in Demand$ Congestion from Base Case)(Nominal $M)								
	Higher Load Forecast	Lower Load Forecast	Athens SPS Out of Service	High Solar Penetration	Higher Natural Gas Prices	Lower Natural Gas Prices	Higher CO2 Emissions Cost	Double Natural Gas Prices Differential	Half Natural Gas Prices Differential
CENTRAL EAST	17	(5)	(0)	(11)	207	(213)	(150)	615	(333)
DUNWOODIE TO LONG ISLAND	3	(3)	(0)	1	9	(13)	(0)	(2)	8
LEEDS PLEASANT VALLEY	28	(28)	2	(5)	16	(25)	(20)	(7)	11
GREENWOOD	19	(18)	(0)	(4)	3	(4)	(4)	(13)	10
NEW SCOTLAND LEEDS	(0)	(0)	0	0	(0)	(0)	(0)	1	(0)
PACKARD HUNTLEY	(0)	(1)	0	(0)	(4)	(4)	(2)	2	(4)
DUNWOODIE MOTTHAVEN	0	0	0	0	0	0	0	0	0
RAINEY VERNON	1	(1)	(0)	(0)	(0)	0	0	(1)	1
E179THST HELLGT ASTORIAE	(0)	(0)	0	(0)	(0)	(0)	(0)	(0)	0
EGRDNCTY 138 VALLYSTR 138 1	1	(1)	(0)	(0)	3	(1)	(0)	(3)	1
Central East – New Scotland Pleasant Valley	44	(33)	2	(16)	223	(238)	(170)	609	(322)
Central East	17	(5)	(0)	(11)	207	(213)	(150)	615	(333)
Western 230 kV System	0	(1)	(33)	(0)	(2)	2	1	(1)	(4)

Table 5-28 below presents a summary of how each of the three transmission groupings chosen for study is affected by each of the scenarios for the entire Study Period. Table 5-29 presents the percentage impact on Demand$ Congestion for each of the scenarios for each of the constraints. As shown, among the scenarios studied, the overall level of natural gas prices and the relative gas prices across the New York Control Area have the greatest impact on the base projection of Demand$ Congestion.

Table 5-28: Impact on Demand$ Congestion (2015$M)

Constraints	Scenarios:(Aggregate Change in Demand$ Congestion from Base Case)(2015 $M)								
	Higher Load Forecast	Lower Load Forecast	Athens SPS Out of Service	High Solar Penetration	Higher Natural Gas Prices	Lower Natural Gas Prices	Higher CO2 Emissions Cost	Double Natural Gas Prices Differential	Half Natural Gas Prices Differential
Central East – New Scotland Pleasant Valley	86	(78)	152	(75)	626	(1,269)	(407)	4,052	(2,643)
Central East	31	(30)	(26)	(65)	604	(1,207)	(375)	4,157	(2,747)
Western 230 kV System	3	(5)	(14)	(5)	(6)	9	14	(1)	(21)

Table 5-29: Impact on Demand$ Congestion

Constraints	Scenarios:(Aggregate Change in Demand $ Congestion from Base Case)(%)								
	Higher Load Forecast	Lower Load Forecast	Athens SPS Out of Service	High Solar Penetration	Higher Natural Gas Prices	Lower Natural Gas Prices	Higher CO2 Emissions Cost	Double Natural Gas Prices Differential	Half Natural Gas Prices Differential
Central East – New Scotland Pleasant Valley	1.6%	-1.5%	2.8%	-1.4%	11.7%	-23.7%	-7.6%	75.6%	-49.3%
Central East	0.6%	-0.6%	-0.5%	-1.3%	12.2%	-24.4%	-7.6%	83.9%	-55.4%
Western 230 kV System	0.9%	-1.4%	-3.8%	-1.4%	-1.7%	2.5%	3.8%	-0.2%	-5.6%

Figures 5-7 through 5-9 show the congestion impact results of ten scenarios performed for the ten-year Study Period. While the table above shows the congestion impact from the scenarios for each of the most congested constraints, the figures below separately show how each of the three transmission groupings chosen for study are affected by each of the scenarios.

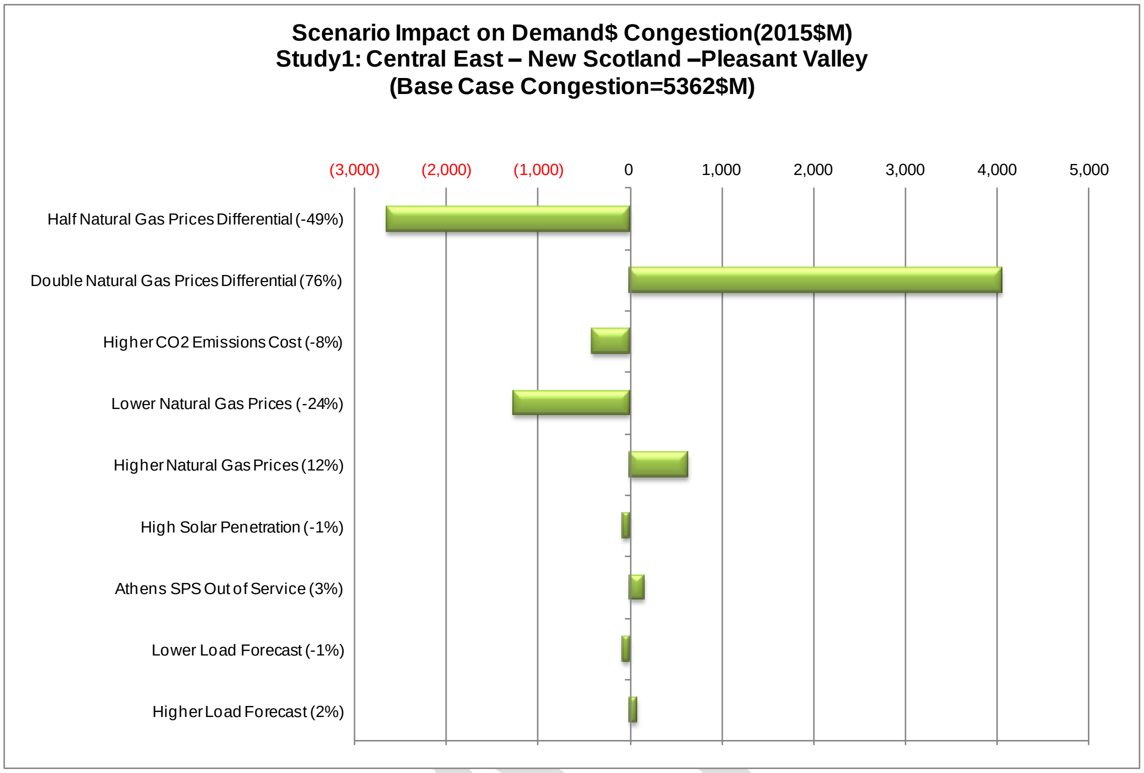

Figure 5-7: Scenario Impact on Central East –New Scotland - Pleasant Valley Congestion

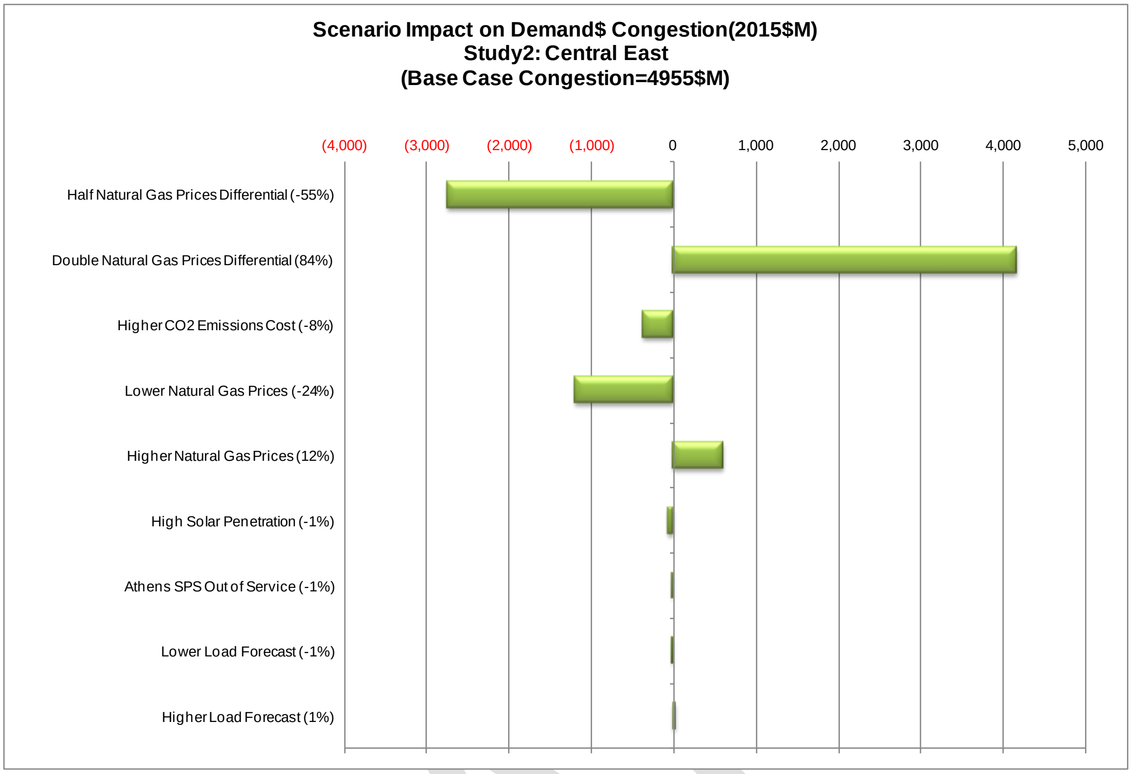

Figure 5-8: Scenario Impact on Central East Congestion

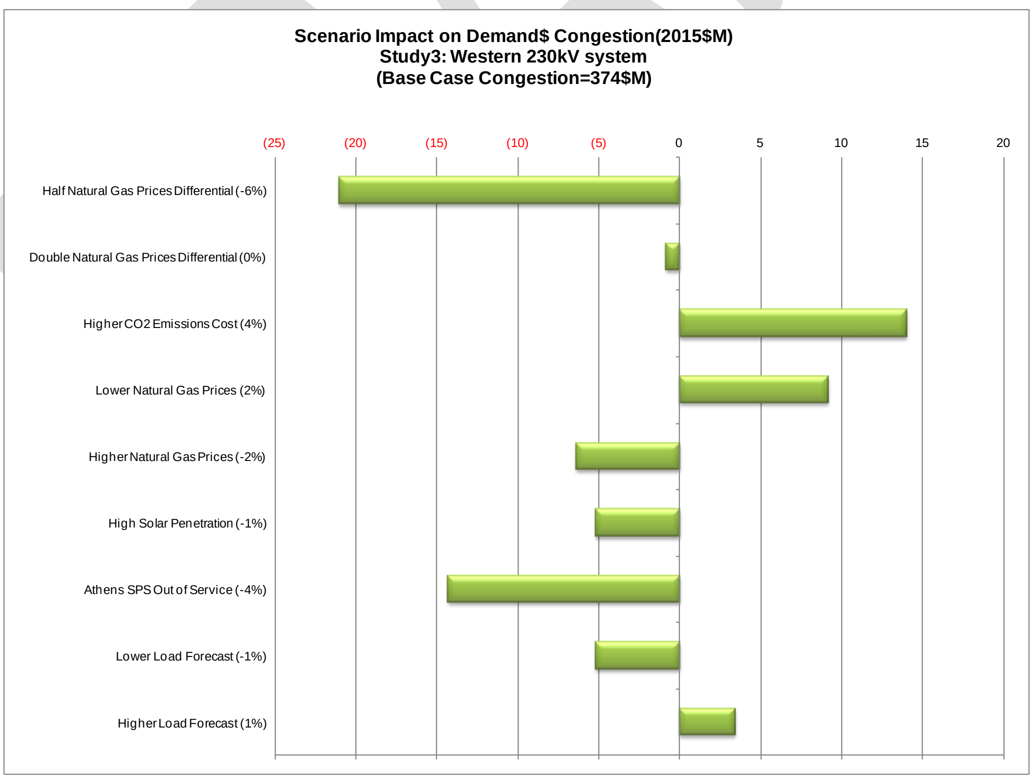

Figure 5-9: Scenario Impact on Western 230 kV System Congestion

Scenario 1: Half Natural Gas Price Differential

To simulate the potential impact of expanded natural gas infrastructure in the New York's Mohawk Valley and Capital regions, *e.g.*, the Constitution Pipeline, this scenario assumed the differential in natural gas prices between Midstate/New England and Upstate was one-half the Base Case differential throughout the 2015-2024 Study Period. This results in an average decrease in the Midstate price of approximately $1.01 per MMBtu.

Scenario 2: Double Natural Gas Price Differential

To simulate the potential impact of an extension in recent trends in higher Capital zone and New England natural gas prices, this scenario assumed the differential in natural gas prices between Midstate/New England and Upstate was double the Base Case differential throughout the 2015-2024 Study Period. This results in an average increase in the Midstate price of approximately $2.03 per MMbtu.

Scenario 3: Higher CO_2 Emissions Cost

This scenario captures the potential impact of CO_2 emission allowance costs being set at the higher end of current forecasts. In setting its base case forecasts, the NYISO reviewed three sets of forecasts developed by third-party consultants and selected a middle-ground estimate. In this scenario, CO_2 emission allowance costs were modeled in the high-range with forecasts ranging from $0.25/ton higher in 2015 to $11.28/ton higher in 2024.

Scenario 4: Lower Natural Gas Prices

This scenario examines congestion costs when natural gas prices are projected to be lower than the base case. In this scenario the NYISO utilized the low-range forecast provided by the USEIA in its 2015AEO. Consequently, as compared to the base case, the low natural gas price case uses prices around 13% lower for Downstate, Midstate and Upstate.

Scenario 5: Higher Natural Gas Prices

This scenario examines congestion costs when natural gas prices are projected to be higher than the base case. In this scenario the NYISO utilized the high-range forecast provided by the USEIA in its 2015AEO. Consequently, as compared to the base case, the high natural gas price case uses prices approximately 7.5% higher in Downstate, Midstate and Upstate.

Scenario 6: High Solar Penetration

The Base Case load forecast included in the 2015 Gold Book incorporated approximately 2,600 MWs of behind-the-meter solar photovoltaic installations. This scenario increased that penetration by 50% for a total of nearly 3,900 MWs of installed Solar PV capacity, distributed across the NYCA zones in the same proportion as the Base Case installations.

Scenario 7: Athens SPS Out of Service

This scenario assumed that the Athens SPS is not in service throughout the Study Period from 2015-2024. The 2015 base case assumed that Athens SPS was in service through June 2024. The Athens SPS system impact study in 2006 indicated a 450 MW increase in the transfer capability of the UPNY-SENY interface with the SPS in service.

Scenario 8: Lower Load Forecast

This scenario examined the impact of a lower load forecast on the cost of congestion. The low load forecast was developed by adjusting downward the annual growth rates for each NYCA zone in the Base load forecast. This resulted in the annual NYCA energy forecast in 2024 being 2,340 GWh (or 1.4%) below the Base forecast.

Scenario 9: Higher Load Forecast

This scenario examined the impact of a higher load forecast on the cost of congestion. The high load forecast was developed by adjusting upward the annual growth rates for each NYCA zone in the Base load forecast. This resulted in the annual NYCA energy forecast in 2024 being 2,950 GWh (or 1.8%) above the Base forecast.

6. 2015 CARIS Findings – Study Phase

The CARIS identified three study areas by considering both historic and forecasted congestion patterns in the NYCA. The NYISO identified those monitored elements that have historically displayed high levels of congestion. It then utilized the GE-MAPS production cost model to identify those elements that would experience congestion through the 2015-2024 Study Period and identified the Central East through Leeds – Pleasant Valley corridors again as the most constrained areas of the NYCA system. The Study however also identified significant congestion in the Western NY 230 kV system which was observed substantially higher in the forecasted period than the historic period. In order to estimate the economic impact of alleviating the identified congestion, the four generic solutions were applied to each of the three study areas and production costs savings were calculated based on the three different ranges of generic costs. This 2015 study shows overall increased levels of production cost savings across comparable interfaces for transmission and reduced levels of production cost savings for generation solutions as compared with the 2013 study.

Table 6-1 shows the projected congestion for each of the three transmission groupings: Central East-New Scotland-Pleasant Valley, Central East, and New Scotland-Pleasant Valley.

Table 6-1: Base Case Projected Congestion 2015-2024

Study	Ten-Year Demand$ Congestion	
	Nominal ($M)	Present Value (2015$M)
Study 1: Central East-New Scotland-Pleasant Valley	6,815	5,362
Study 2: Central East	6,289	4,955
Study 3: Western 230kV System	486	374

The application of the generic solutions to the three study areas all result in production cost savings expressed in 2015 present values, as shown in Table 6-2.

Table 6-2: Production Cost Savings 2015-2024 (2015$M)

	Ten-Year Production Cost Savings ($2015M)			
	Transmission Solution	Generation Solution	Demand Response Solution	Energy Efficiency Solution
Study 1: Central East-New Scotland-Pleasant Valley	305	133	81	2,287
Study 2: Central East	262	47	40	1,162
Study 3: Western 230kV System	199	186	29	1,054

In Phase 1, CARIS compares the present value of the production cost savings benefit over the ten-year Study Period to the present value of fixed costs based on a 16.26% carrying cost charge, for transmission and generation solutions, to determine a benefit/cost ratio, as presented in Table 6-3. A Capital Recovery Factor is not applied to energy efficiency or demand response solutions. See Section 5.4 for a detailed explanation.

Table 6-3: Benefit/Cost Ratios

	Solution	Cost Category		
		Low	Mid	High
CE-NS-PV	Transmission	0.50	0.36	0.27
	Generation	0.07	0.05	0.04
	Demand Response	0.14	0.11	0.09
	Energy Efficiency	1.10	0.99	0.91
CE	Solution	Cost Category		
		Low	Mid	High
	Transmission	0.76	0.58	0.40
	Generation	0.06	0.04	0.03
	Demand Response	0.14	0.11	0.09
	Energy Efficiency	1.11	1.01	0.92
West	Solution	Cost Category		
		Low	Mid	High
	Transmission	1.96	1.39	1.04
	Generation	0.22	0.17	0.13
	Demand Response	0.10	0.08	0.06
	Energy Efficiency	1.01	0.91	0.84

In conclusion, this CARIS Phase 1 study provides: (a) projections of congestion in the NYCA system; (b) present value of ten-year production cost savings ranging from $29M to $2,287M resulting from the application of various generic transmission, generation, energy efficiency and demand response solutions; and (c) the Benefit/Cost ratios as high as 1.96 and as low as 0.03 depending on the high-medium-low generic project cost estimates.

For the two Central New York studies, the transmission, generation and demand response solutions produced a B/C ratio less than one in each of the cost estimate categories, reflecting the fact that their projected costs outweighed their estimated production cost savings over the Study Period. The energy efficiency solution for the Central East constraint produced a B/C ratio greater than one in the Low and Mid cost estimates, and, similarly, the energy efficiency solution for the Central East-New Scotland-Pleasant Valley constraint produced a B/C ratio greater than 1.0 for the low cost estimate and approximately 1.0 (0.99) for the Mid cost estimate. For the Western NY study, the Transmission solution had B/C ratios in excess of 1.0 in each of the cost categories. Similar to the Central New York studies, the generation and demand response solutions had B/C ratios well below 1.0, and the energy efficiency solution was greater than 1.0 in the Low cost estimate category and approaching 1.0 for the Mid cost estimate.

As noted, the benefits captured in the B/C ratios are limited to production cost savings. The B/C ratios, for example, do not capture reduced Demand$ Congestion which are $2.2B – $2.5B (2015$) for the Central NY transmission solutions; and nearly $340M (2015$) for the Western NY transmission solution. For example, the Variant 1 estimate[30] of the capacity market impact, if the capacity benefits were to be realized, for the Central East-New Scotland-Pleasant Valley transmission solution was a savings of $377M (2015$); for the Central East transmission solution, an increase of $82M (2015$); and the Western NY 230 kV system transmission solution, no change.

Additionally, the scenario analyses provide information on new or increased projected congestion costs resulting from changes in variables selected for scenario analyses (see Appendix I).

[30] See footnote 5 for a description of the capacity market metrics, which were developed in compliance with Section 31.3.1.3.5.6 of the Tariff.

7. Next Steps

In addition to the CARIS Phase 1 Study, any interested party can request additional studies or use the CARIS Phase 1 results for guidance in submitting a request for a Phase 2 study.

7.1. Additional CARIS Studies

In addition to the three CARIS studies, any interested party may request an additional study of congestion on the NYCA bulk power system. Those studies can analyze the benefits of alleviating congestion with all types of resources, including transmission, generation and demand response, and compare benefits to costs.

7.2. Phase 2 – Specific Transmission Project Phase

The NYISO staff will commence Phase 2 – the Project Phase – of the CARIS process following the approval of the Phase 1 report by the NYISO Board of Directors. The model for Phase 2 studies would include known changes to the system configuration that meet base case inclusion rules and would be updated with any new load forecasts, fuel costs, and emission costs projections upon review and discussion by stakeholders. Phase 2 will provide a benefit/cost assessment for each specific transmission project that is submitted by Developers who seek regulated cost recovery under the NYISO's Tariff.

Transmission projects seeking regulated cost recovery will be further assessed by NYISO staff to determine whether they qualify for cost allocation and cost recovery under the NYISO Tariff.[31] To qualify, the total capital cost of the project must exceed $25 million, the benefits as measured by the NYCA-wide production cost savings must exceed the project cost measured over the first ten years from the proposed commercial operation date, and a super-majority (≥ 80%) of the weighted votes cast by the beneficiaries must be in favor of the project. Additional details on the Phase 2 process can be found in the Economic Planning Manual.[32]

7.3. Project Phase Schedule

The NYISO staff will perform benefit/cost analysis for submitted economic transmission project proposals for and, if a Developer seeks cost recovery, will

[31] Market-based responses to congestion identified in Phase 1 of the CARIS are not eligible for regulated cost recovery, and therefore are not obligated to follow the requirements of Phase 2. Cost recovery of market-based projects shall be the responsibility of the Developer.

[32] http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Planning/epp_caris_mnl.pdf

determine beneficiaries and conduct cost allocation calculations. The results of the Phase 2 analyses will provide a basis for beneficiary voting on each proposed transmission project.

The next CARIS cycle is scheduled to begin in 2017.

Appendix A – Glossary

TERM	DEFINITION
Ancillary Services	Services necessary to support the transmission of Energy from Generators to Loads, while maintaining reliable operation of the NYS Power System in accordance with Good Utility Practice and Reliability Rules. Ancillary Services include Scheduling, System Control and Dispatch Service; Reactive Supply and Voltage Support Service (or Voltage Support Service); Regulation Service; Energy Imbalance Service; Operating Reserve Service (including Spinning Reserve, 10-Minute Non-Synchronized Reserves and 30-Minute Reserves); and Black Start Capability. [FROM SERVICES TARIFF]
Bid Production Cost	Total cost of the Generators required to meet Load and reliability Constraints based upon Bids corresponding to the usual measures of Generator production cost (*e.g.*, running cost, Minimum Generation Bid, and Start Up Bid). [FROM SERVICES TARIFF]
Bulk Power Transmission Facility (BPTF)	Transmission facilities that are system elements of the bulk power system which is the interconnected electrical system within northeastern North America comprised of system elements on which faults or disturbances can have a significant adverse impact outside of the local area.
Business Issues Committee (BIC)	A NYISO committee that is charged with, among other things, the responsibility to establish procedures related to the efficient and non-discriminatory operation of the electricity markets centrally coordinated by the NYISO, including procedures related to bidding, Settlements and the calculation of market prices.
Capacity	The capability to generate or transmit electrical power, or the ability to reduce demand at the direction of the NYISO.
Comprehensive Reliability Plan (CRP)	A biennial study undertaken by the NYISO that evaluates projects offered to meet New York's future electric power needs, as identified in the Reliability Needs Assessment (RNA). The CRP may trigger electric utilities to pursue regulated solutions to meet Reliability Needs if market-based solutions will not be available by that point.
Comprehensive System Planning Process (CSPP)	The Comprehensive System Planning Process encompasses reliability planning, economic planning, Public Policy Requirements planning, cost allocation and cost recovery, and interregional planning coordination.
Congestion	Congestion on the transmission system results from physical limits on how much power transmission equipment can carry without exceeding thermal, voltage and/or stability limits determined to maintain system reliability. If a lower cost generator cannot transmit its available power to a customer because of a physical transmission constraint, the cost of dispatching a more expensive generator is the congestion cost.
Congestion Rent	The opportunity costs of transmission Constraints on the NYS Bulk Power Transmission System. Congestion Rents are collected by the NYISO from Loads through its facilitation of LBMP Market Transactions and the collection of Transmission Usage Charges from Bilateral Transactions.

Contingencies	Electrical system events (including disturbances and equipment failures) that are likely to happen.
Day Ahead Market (DAM)	A NYISO-administered wholesale electricity market in which capacity, electricity, and/or Ancillary Services are auctioned and scheduled one day prior to use. The DAM sets prices as of 11 a.m. the day before the day these products are bought and sold, based on generation and energy transaction bids offered in advance to the NYISO. More than 90% of energy transactions occur in the DAM.
DC tie-lines	A high voltage transmission line that uses direct current for the bulk transmission of electrical power between two control areas.
Demand Response	A mechanism used to encourage consumers to reduce their electricity use during a specified period, thereby reducing the peak demand for electricity.
Eastern Interconnection Planning Collaborative (EIPC)	A group of planning authorities convened to establish processes for aggregating the modeling and regional transmission plans of the entire Eastern Interconnection and for performing inter-regional analyses to identify potential opportunities for efficiencies between regions in serving the needs of electrical customers.
Economic Dispatch of Generation	The operation of generation facilities to produce energy at the lowest cost to reliably serve consumers.
Electric System Planning Working Group (ESPWG)	A NYISO governance working group for Market Participants designated to fulfill the planning functions assigned to it. The ESPWG is a working group that provides a forum for stakeholders and Market Participants to provide input into the NYISO's Comprehensive System Planning Process (CSPP), the NYISO's response to FERC reliability-related Orders and other directives, other system planning activities, policies regarding cost allocation and recovery for reliability projects, and related matters.
Energy Efficiency Portfolio Standard (EEPS)	A statewide program ordered by the NYSPSC in response to the Governor's call to reduce New Yorkers' electricity usage by 15% of forecast levels by the year 2015, with comparable results in natural gas conservation. Also known as 15x15.
Exports	A Bilateral Transaction or purchases from the LBMP Market where the Energy is delivered to a NYCA Interconnection with another Control Area. [FROM SERVICES TARIFF]
External Areas	Neighboring Control Areas including HQ, ISO-NE, PJM, IESO
Federal Energy Regulatory Commission (FERC)	The federal energy regulatory agency within the US Department of Energy that approves the NYISO's tariffs and regulates its operation of the bulk electricity grid, wholesale power markets, and planning and interconnection processes.
FERC Form 715	An annual transmission planning and evaluation report required by the FERC – filed by the NYISO on behalf of the transmitting utilities in New York State.

FERC Order No. 890	Adopted by FERC in February 2007, Order 890 is a change to FERC's 1996 open access regulations (established in Orders 888 and 889). Order 890 is intended to provide for more effective competition, transparency and planning in wholesale electricity markets and transmission grid operations, as well as to strengthen the Open Access Transmission Tariff (OATT) with regard to non-discriminatory transmission service. Order 890 requires Transmission Providers – including the NYISO – have a formal planning process that provides for a coordinated transmission planning process, including reliability and economic planning studies.
Grandfathered Rights	The transmission rights associated with: (1) Modified Wheeling Agreements; (2) Transmission Facility Agreements with transmission wheeling provisions; and (3) Third Party Transmission Wheeling Agreements (TWA) where the party entitled to exercise the transmission rights associated with such Agreements has chosen, as provided in the Tariff, to retain those rights rather than to convert those rights to TCCs. [FROM SERVICES TARIFF]
Grandfathered TCCs	The TCCs associated with: (1) Modified Wheeling Agreements; (2) Transmission Facility Agreements with transmission wheeling provisions; and (3) Third Party TWAs where the party entitled to exercise the transmission rights associated with such Agreements has chosen, as provided by the Tariff, to convert those rights to TCCs. [FROM SERVICES TARIFF]
Heat Rate	A measurement used to calculate how efficiently a generator uses heat energy. It is expressed as the number of BTUs of heat required to produce a kilowatt-hour of energy. Operators of generating facilities can make reasonably accurate estimates of the amount of heat energy a given quantity of any type of fuel, so when this is compared to the actual energy produced by the generator, the resulting figure tells how efficiently the generator converts that fuel into electrical energy.
High Voltage Direct Current (HVDC)	A transmission line that uses direct current for the bulk transmission of electrical power, in contrast with the more common alternating current systems. For long-distance distribution, HVDC systems are less expensive and suffer lower electrical losses.
Investment Hurdle Rate	The minimum acceptable rate of return.
Imports	A Bilateral Transaction or sale to the LBMP Market where Energy is delivered to a NYCA Interconnection from another Control Area.
Independent Market Monitoring Unit	Consulting firm retained by the NYISO Board pursuant to Article 4 of the NYISO's Market Monitoring Plan.
Independent System Operator (ISO)	An organization, formed at the direction or recommendation of the Federal Energy Regulatory Commission (FERC), which coordinates, controls and monitors the operation of the electrical power system, usually within a single US State, but sometimes encompassing multiple states.

Installed Capacity (ICAP)	A generator or load facility that complies with the requirements in the Reliability Rules and is capable of supplying and/or reducing the demand for energy in the NYCA for the purpose of ensuring that sufficient energy and capacity are available to meet the Reliability Rules.
Installed Reserve Margin (IRM)	The amount of installed electric generation capacity above 100% of the forecasted peak electric consumption that is required to meet New York State Reliability Council (NYSRC) resource adequacy criteria. Most planners consider a 15-20% reserve margin essential for good reliability.
Load	A term that refers to either a consumer of Energy or the amount of demand (MW) or Energy (MWh) consumed by certain consumers. [FROM SERVICES TARIFF]
Locational Capacity Requirement (LCR)	Locational Capacity Requirement specifies the minimum amount of installed capacity that must be procured from resources situated specifically within a locality (Zone K and Zone J). It considers resources within the locality as well as the transmission import capability to the locality in order to meet the resource adequacy reliability criteria of the New York State Reliability Council (NYSRC) and the Northeast Power Coordinating Council (NPCC).
Load Serving Entity (LSE)	Any entity, including a municipal electric system and an electric cooperative, authorized or required by law, regulatory authorization or requirement, agreement, or contractual obligation to supply Energy, Capacity and/or Ancillary Services to retail customers located within the NYCA, including an entity that takes service directly from the NYISO to supply its own Load in the NYCA. [FROM SERVICES TARIFF]
Load Zones	The eleven regions in the NYCA connected to each other by identified transmission interfaces. Designated as Load Zones A-K.
Local Transmission Planning Process (LTPP)	The first step in the Comprehensive System Planning Process (CSPP), under which stakeholders in New York's electricity markets participate in local transmission planning.
Locational Based Marginal Pricing (LBMP)	The price of Energy at each location in the NYS Transmission System.
Market Analysis and Portfolio Simulation (MAPS) Software	An analytic tool for market simulation and asset performance evaluations.
Multi-Area Reliability Simulation (MARS) Software	An analytic tool for market simulation to assess the reliability of a generation system comprised of any number of interconnected areas.
Market Based Solution	Investor-proposed projects that are driven by market needs to meet future reliability requirements of the bulk electricity grid as outlined in the RNA. Those solutions can include generation, transmission and Demand Response Programs.

Market Participant	An entity, excluding the NYISO, that produces, transmits sells, and/or purchases for resale capacity, energy and ancillary services in the wholesale market. Market Participants include: customers under the NYISO tariffs, power exchanges, TOs, primary holders, load serving entities, generating companies and other suppliers, and entities buying or selling transmission congestion contracts.
New York Control Area (NYCA)	The area under the electrical control of the NYISO. It includes the entire state of New York, and is divided into 11 zones.
New York Independent System Operator (NYISO)	Formed in 1997 and commencing operations in 1999, the NYISO is a not-for-profit organization that manages New York's bulk electricity grid – a 11,009-mile network of high voltage lines that carry electricity throughout the state. The NYISO also oversees the state's wholesale electricity markets. The organization is governed by an independent Board of Directors and a governance structure made up of committees with Market Participants and stakeholders as members.
New York State Reliability Council (NYSRC)	A not-for-profit entity whose mission is to promote and preserve the reliability of electric service on the New York State Power System by developing, maintaining, and, from time-to-time, updating the Reliability Rules which shall be complied with by the New York Independent System Operator (NYISO) and all entities engaging in electric transmission, ancillary services, energy and power transactions on the New York State Power System.
Nomogram	Nomograms are used to model relationships between system elements. These can include; voltage or stability related to load level or generator status; two interfaces related to each other; generating units whose output is related to each other; and operating procedures.
Northeast Coordinated System Planning Protocol (NCSPP)	ISO New England, PJM and the NYISO work together under the Northeast Coordinated System Planning Protocol (NCSPP), to analyze cross-border issues and produce a regional electric reliability plan for the northeastern United States.
Operating Reserves	Capacity that is available to supply Energy or reduce demand and that meets the requirements of the NYISO. [SERVICES TARIFF TERM]
Overnight Costs	Direct permitting, engineering and construction costs with no allowances for financing costs.
Phase Angle Regulator (PAR)	Device that controls the flow of electric power in order to increase the efficiency of the transmission system.
Proxy Generator Bus	A proxy bus located outside the NYCA that is selected by the NYISO to represent a typical bus in an adjacent Control Area and for which LBMP prices are calculated. The NYISO may establish more than one Proxy Generator Bus at a particular Interface with a neighboring Control Area to enable the NYISO to distinguish the bidding, treatment and pricing of products and services at the Interface.
Public Policy Transmission Planning Process (PPTPP)	The process by which the ISO solicits needs for transmission driven by Public Policy Requirements, evaluates all solutions on a comparable basis, and selects the more efficient or cost effective transmission solution, if any, for eligibility for cost allocation under the ISO Tariffs.
Regional Greenhouse Gas Initiative (RGGI)	A cooperative effort by ten Northeast and Mid-Atlantic states to limit greenhouse gas emissions using a market-based cap-and-trade approach.

Regulated Backstop Solution	Proposals required of certain TOs to meet Reliability Needs as outlined in the RNA. Those solutions can include generation, transmission or Demand Response. Non-Transmission Owner developers may also submit regulated solutions. The NYISO may call for a Gap solution if neither market-based nor regulated backstop solutions meet Reliability Needs in a timely manner. To the extent possible, the Gap solution should be temporary and strive to ensure that market-based solutions will not be economically harmed. The NYISO is responsible for evaluating all solutions to determine if they will meet identified Reliability Needs in a timely manner.
Regulation Service	An Ancillary Service. See glossary definition for Ancillary Services.
Reliability Need	A condition identified by the NYISO in the RNA as a violation or potential violation of Reliability Criteria. (OATT TERM)
Reliability Needs Assessment (RNA)	A biennial report that evaluates resource adequacy and transmission system security over a ten-year planning horizon, and identifies future needs of the New York electric grid. It is the one of the three primary planning processes in the NYISO's CSPP.
Security Constrained Unit Commitment (SCUC)	A process developed by the NYISO, which uses a computer algorithm to dispatch sufficient resources, at the lowest possible Bid Production Cost, to maintain safe and reliable operation of the NYS Power System.
Special Case Resource (SCR)	A NYISO demand response Demand Response program designed to reduce power usage by businesses and large power users qualified to participate in the NYISO's ICAP market. Companies that sign up to serve as SCRs are paid in advance for agreeing to reduce power consumption upon NYISO request.
Stakeholders	A person or group that has an investment or interest in the functionality of New York's transmission grid and markets.
Thermal transfer limit	The maximum amount of heat a transmission line can withstand. The maximum reliable capacity of each line, due to system stability considerations, may be less than the physical or thermal limit of the line.
Transfer Capability	The amount of electricity that can flow on a transmission line at any given instant, respecting facility rating and reliability rules.
Transmission Congestion Contract (TCC)	The right to collect, or obligation to pay, Congestion Rents in the Day Ahead Market for Energy associated with a single MW of transmission between a specified Point Of Injection and Point Of Withdrawal. TCCs are financial instruments that enable Energy buyers and sellers to hedge fluctuations in the price of transmission. (SERVICES TARIFF TERM)
Transmission Constraint	Limitations on the ability of a transmission facility to transfer electricity during normal or emergency system conditions.
Transmission District	The geographic area served by the Investor Owned Transmission Owners and LIPA, as well as the customers directly interconnected with the transmission facilities of the Power Authority of the State of New York. (SERVICES TARIFF TERM)
Transmission Interface	A defined set of transmission facilities that separate Load Zones and that separate the NYCA from adjacent Control Areas. (SERVICES TARIFF TERM)

Transmission Owner (TO)	A public utility or authority that provides Transmission Service under the Tariff
Transmission Planning Advisory Subcommittee (TPAS)	A group of Market Participants that advises the NYISO Operating Committee and provides support to the NYISO Staff in regard to transmission planning matters including transmission system reliability, expansion, and interconnection.